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EVALUATION OF CONVENTIONAL POWER SYSTEMS

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Foreword

The NASA Office of Energy Programs is presently conducting a study of the potential utility of large orbital central power stations as a possible means to help meet our country's demands for electricity. As part of this study, JPL has been directed to perform a survey of potential terrestrial energy conversion systems for comparison with orbital central power stations. The candidate terrestrial options being reviewed include conventional power plants and both solar thermal and photovoltaic conversion. This report presents an evaluation of conventional power systems. The work was performed by personnel at the University of California at Berkeley under a subcontract to JPL.

The work was performed under the technical direction and guidance of Mr. Richard Caputo of JPL. The Cognizant NASA Program Manager is Mr. Simon Manson of the Energy Technology Applications Division.

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We appreciate the assistance of Professor Melvyn Branch of the Mechanical Engineering Department, University of California, Berkeley. T. English of JPL was very helpful in reviewing this study and provided many constructive suggestions. In addition, we are thankful for the patience and skill of our typists; Linda Elliott, Linda Marczak, Debbie Tyber and Mari Wilson, and the JPL typist, Peggy Panda. Of course, all errors are the authors' responsibility.

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Chapter I INTRODUCTION AND SUMMARY

This report is a review of the technical, economic, and environmental characteristics of (thermal, non-solar) electric-power plants that are likely to see widespread use in the United States in the remainder of this century. The fuel cycle, from extraction of new fuel to final waste management, is included. We have selected for particularly thorough review eight examples of the fossil-fuel and nuclear technologies most likely to be heavily relied upon. The study has employed existing knowledge and literature and does not develop any new analytical tools or experimental data. The report does not address several important issues about electric energy production: it does not estimate the resource base of the various fuels; it does not evaluate the costs and impacts of exploration for fuels; it does not evaluate the costs and impacts of transmission or final end use of the electricity; it makes no attempt to address the questions related to the growth in demand for electricity or try to predict what that growth will or should be; it makes no attempt to evaluate where alternative sources might be substituted for electricity; it makes little attempt to evaluate the energy systems being developed in other parts of the world.

The usefulness of this report is that it attempts to place the eight reference electric energy systems in the same assessment framework. The systems are evaluated in the same time period, with the same economic ground-rules, and with the same categories of environmental and health impacts. Most of the costs, resource requirements, emissions and impacts for each system have been normalized to the electrical output of the system in megawatt-years (Mwe-yr). This approach should provide useful information, not only for comparing these eight systems, but also for assessing the characteristics of other systems which might become available during or at the end of this period.

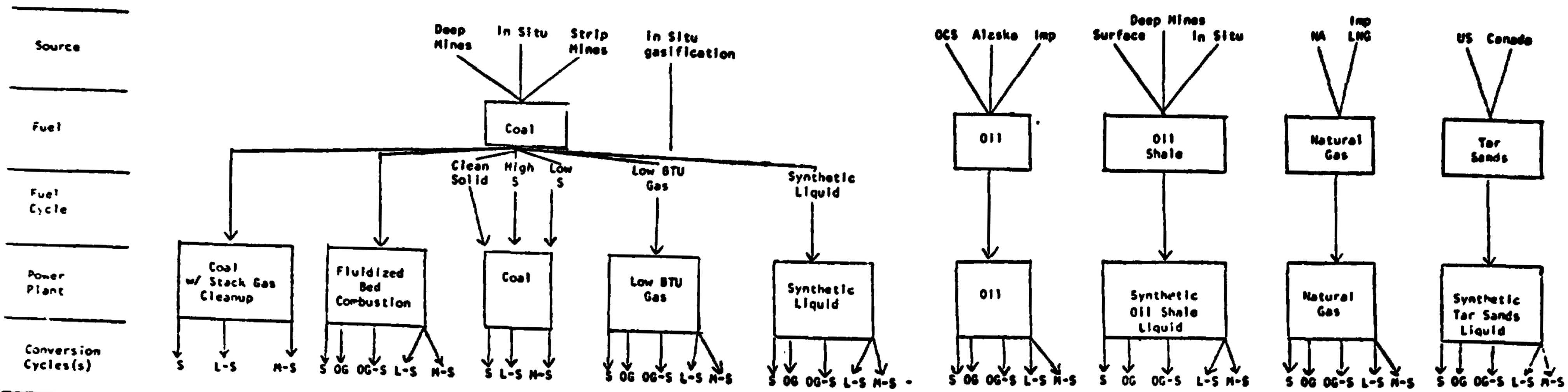
Selection of Systems

Figures I-1-a,b,c illustrate the fuel cycles of most non-solar electric-power systems of present interest in the technical community. No judgment is implied, in these figures, about the technical or economic feasibility of the systems shown, and in fact, most of the systems are unlikely to contribute a very significant portion of U. S. generation capacity in the period before the year 2000. Figures I-2-a,b,c illustrate a smaller set of systems--those we believe may actually become available in this time period or, as in the case of fusion, might become important in the early part of the next century. Those systems marked with asterisks in Figures I-2-a,b,c make up the still smaller subset whose members might individually supply more than 5% of U.S. electricity production in the year 2000. (We think high-Btu coal gasification, coal liquefaction, and imported liquefied natural gas (LNG) are likely to be important energy technologies in this time period, but not for electricity generation.)

Eight of these final systems (all but conservation) were examined in detail in the present study. In our view, unless there are significant political changes, unexpected technical or resource breakthroughs, or major changes in public attitude, these eight systems are the non-solar electricity-producing technologies most likely to be of significance in the period 1990-2000. If terrestrial or satellite solar power systems should become available by the year 2000, utilities will likely be choosing between these solar systems and the eight power systems in our final group.

Conservation can also be considered a source of electric power, because electricity saved in one application becomes available for use in others. Indeed, we believe conservation will be the most important "new source" in the time frame

Figure 1-1-a: Fossil Electric-Power Alternatives

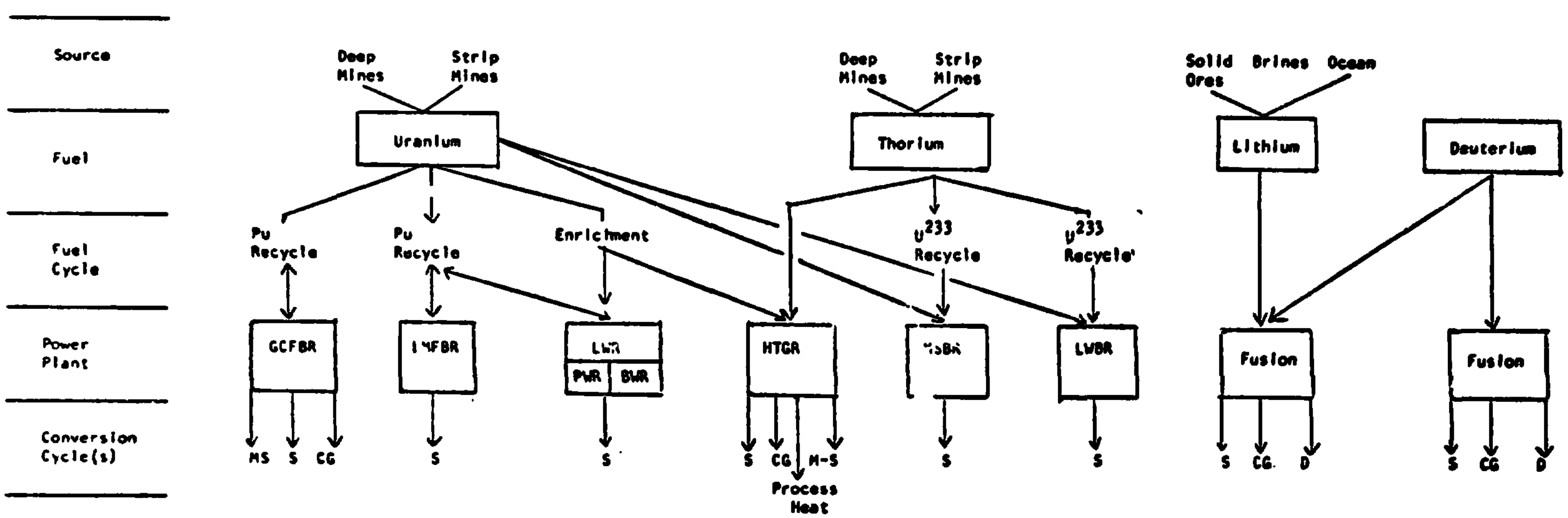


Key
S - Steam Turbine
OG - Open Cycle Gas Turbine
L - Liquid Metal Topping
M - Open Cycle MHD Topping
NA - Natural Gas
OCS - Outer Continental Shelf
IMP - Imported
LNG - Liquid Natural Gas

Other Possibilities

-- High Btu Coal Gasification
-- Closed Cycle Gas Turbines
-- Closed Cycle MHD Topping
-- Organic Bottoming
-- Thermionic Topping
-- Fuel Cells
-- Supercritical CO_2 Topping

Figure 1-1-b: Nuclear Electric-Power Alternatives

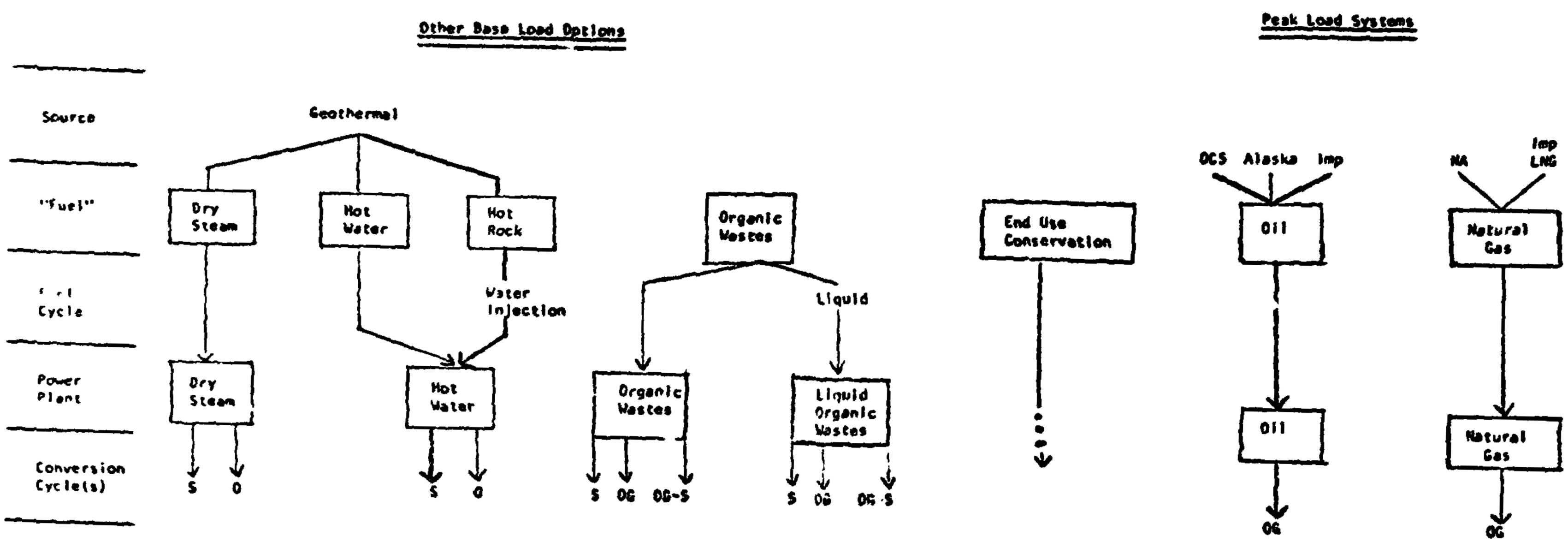


Key
S - Steam Turbine
CG - Closed Cycle Gas Turbine
M - Open Cycle MHD Topping
D - Direct Electric Conversion
BR - Breeder Reactor
F - Fast
GC - Gas Cooled
LM - Liquid Metal

LWR - Light Water Reactor
P - Pressurized
B - Boiling
GR - Gas Reactor
HT - High Temperature
MS - Molten Salt

Other Possibilities
- HWR - Heavy Water Reactor
- AGR - Advanced Gas Reactor
- SGHWR - Steam Generating Heavy Water Reactor
- Organic Bottoming Cycles
- Candu - Canadium HWR

Figure 1-1-c: Other Thermal, Non-Solar Electric-Power Alternati·es



Key
S - Steam Turbine
O - Organic Cycle
OG - Ope· Cycle G·· Tur··ne

Figure 1-2-a: Likely Fossil Electric-Power Systems by the Year 2000

(*Systems with highest chance of individually supplying more than 5% of electricity production by 2000)

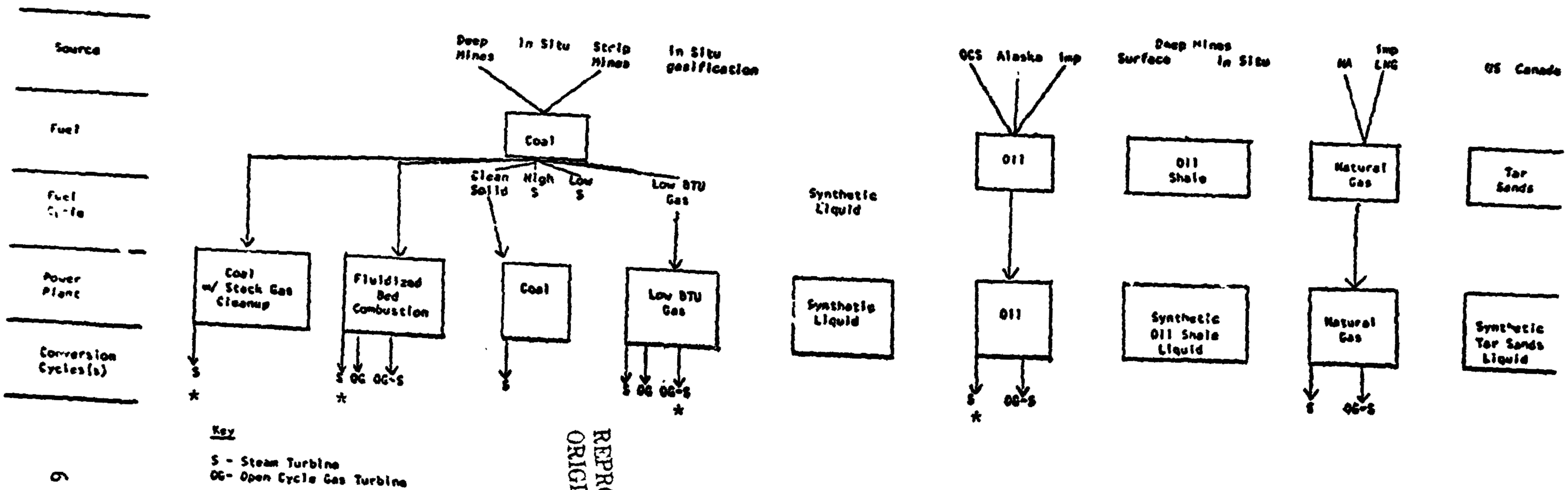


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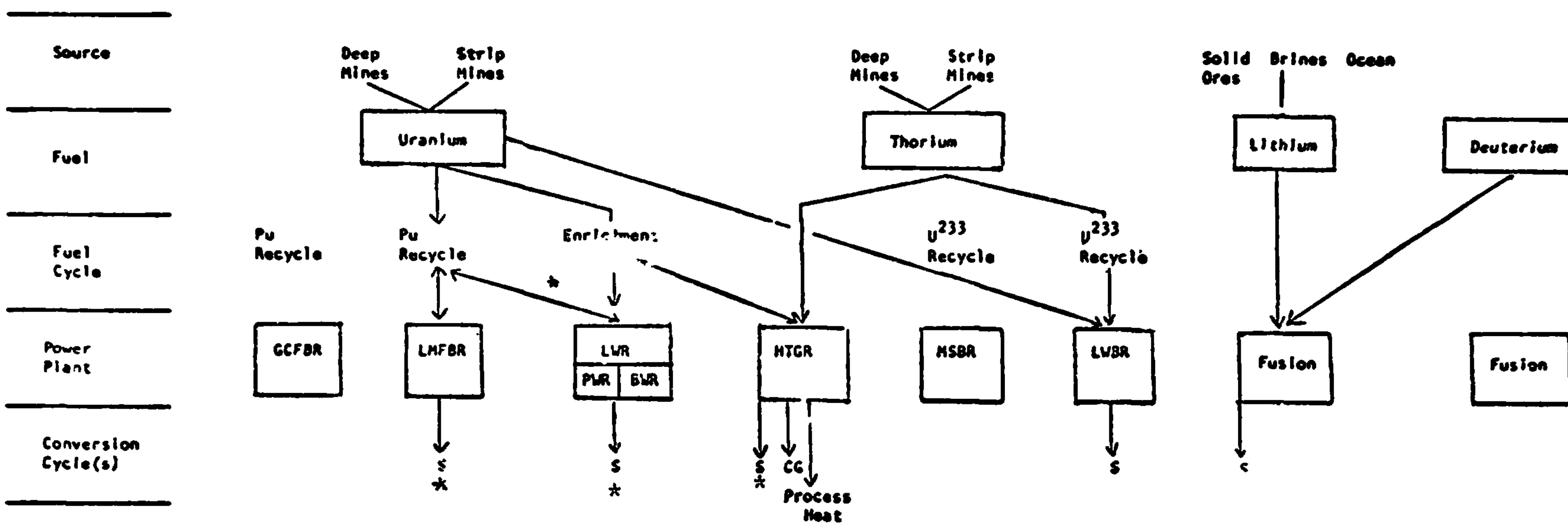
Figure 1-2-b: Likeiy Nuclear Electric-Power Systems by the Year 2000

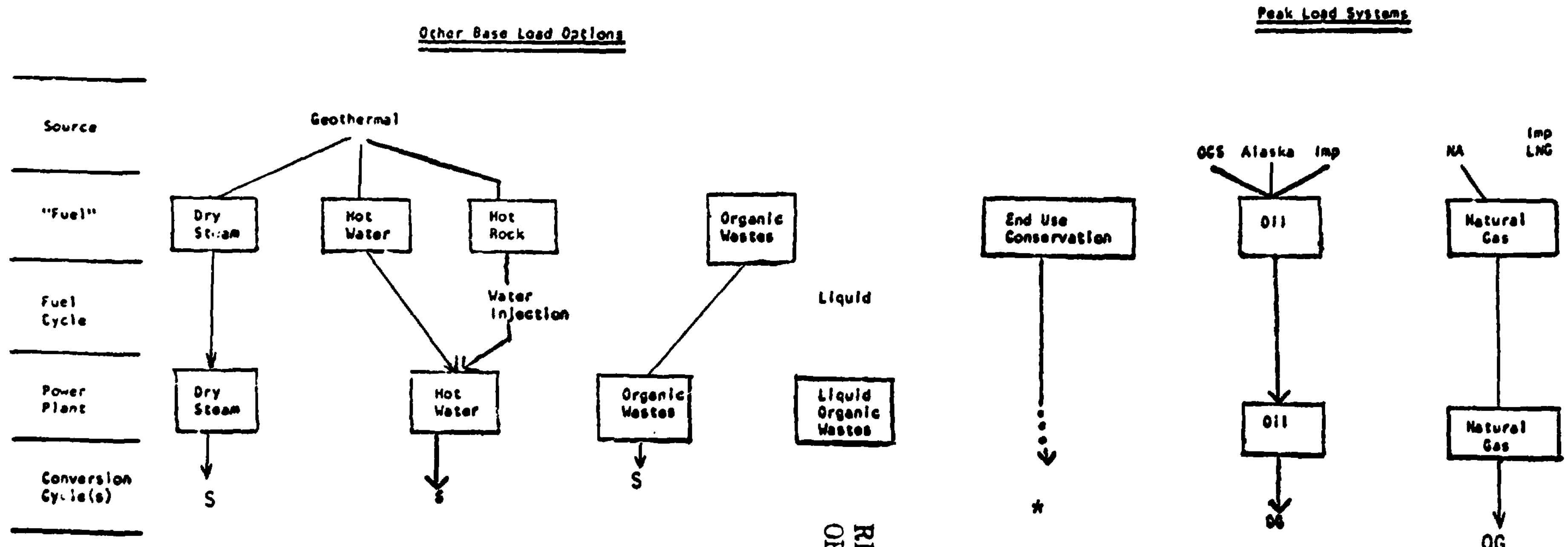
(*Systems with highest chance of individually supplying more than 5% of electricity production by 2000)



Key
S -- Steam Turbine
CG - Closed Cycle Gas Turbine

Figure 1-2-c: Other Thermal, Non-Solar Electric-Power Systems by the Year 2000

(*System with highest chance of individually supplying more than 5% of electricity production by 2000.)



Key
S - Steam Turbine
O - Organic Cycle
OG - Open Cycle Gas Turbine

considered. Because of the time and staff limitations of our project, however, we have not provided a detailed analysis of conservation's economic and environmental effects The most comprehensive such analysis in the literature to date is the report of the Energy Policy Project of the Ford Foundation (24).

Some Summary Comparisons

In this section, several of the most important costs and impacts of electric power production are summarized in a form that facilitates comparisons between the eight alternative technologies. Each system has inherent characteristics which made it unique, and truly meaningful comparisons require more information and synthesis than the graphs provide in the following summary sections. To avoid misunderstanding of the information presented in these sections, the reader is advised to read the rest of this report and to study the tables in Appendices A-H.

Comparisons: Costs and Resource Utilization

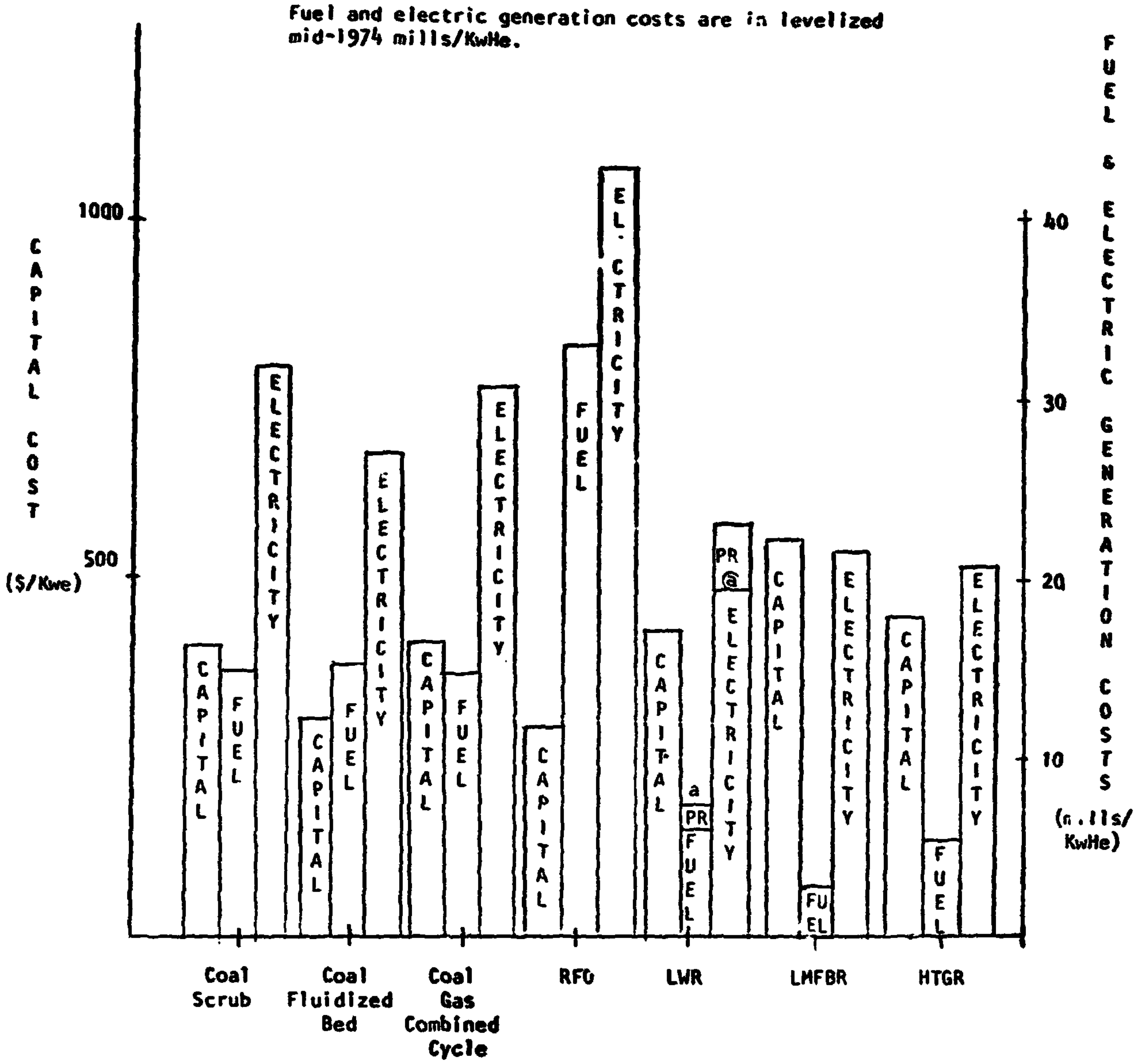
Extensive cost and resource utilization data were collected for the eight electric-power generation systems for this study. The raw data normalized to one megawatt-year of electrical output at the power plant are included in the Appendices. In Section-III-A these data are summarized and the sensitivity of electric generation costs to variations in some of the base-case parameters are explored. A more concise summary follows here.

The cost of electric generation is conventionally broken down into its capital, fuel, and operation and maintenance components. Although in the present study the conventional definitions of these cost components are not strictly adhered to in calculating electric generation costs, we can appropriately use them to summarize some of the cost data that were collected (see footnotes in Table A-1). In this study the base-case referes to technological and economic conditions that are expected to exist in the electric-power industry in about 1990. The base-case cost data are summarized in Figure 1-3. The capital costs shown are in mid-1974 dollars and assume no escalation or de-escalation between now and 1990. The fuel costs and electric

Figure I-3: Base Case Fuel, Capital and Electric Generation Costs.

Capital costs are in mid-1974 dollars and include interest during construction.

Fuel and electric generation costs are in levelized mid-1974 mills/KwHe.



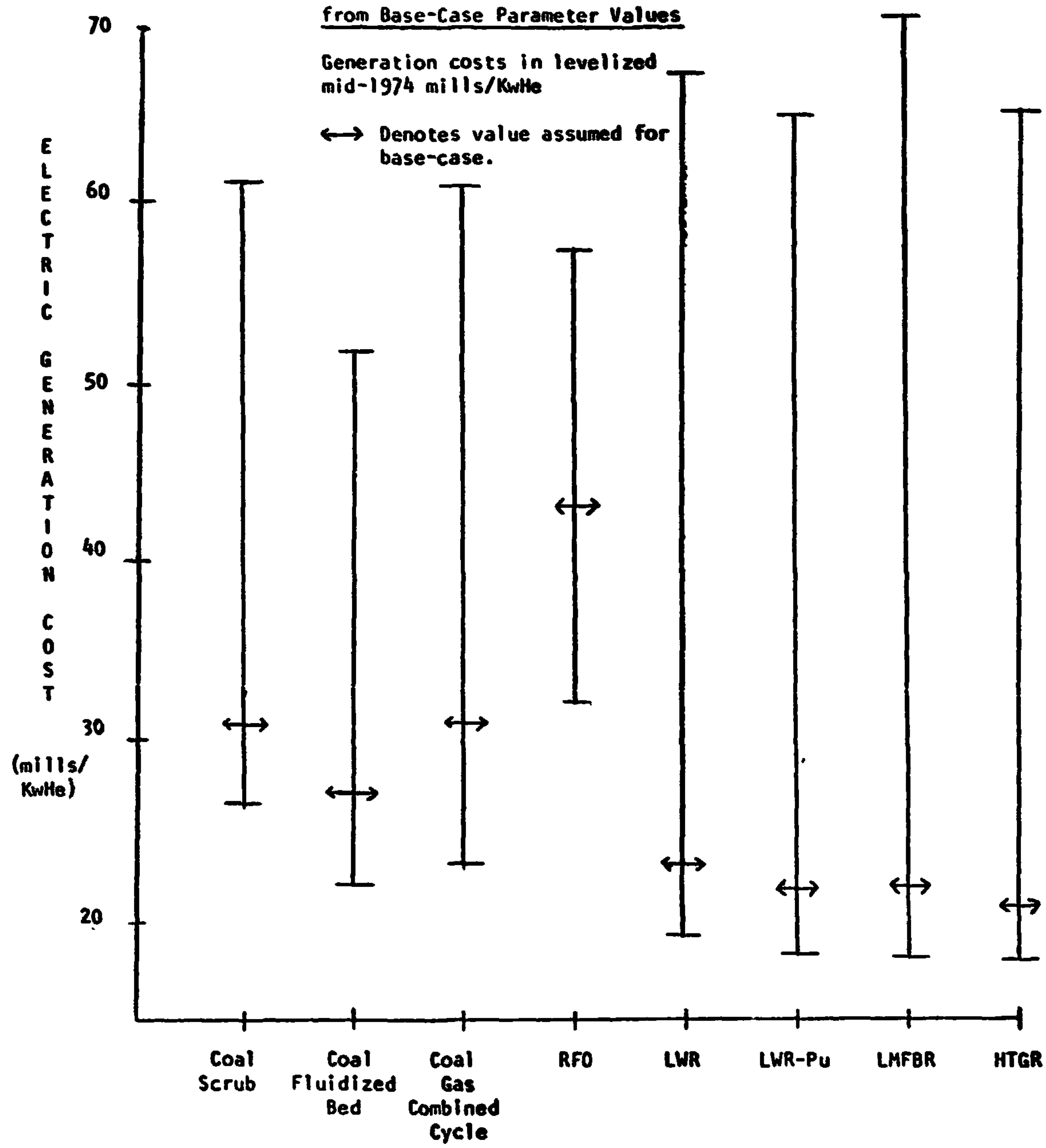
a. The PR areas denote the cost savings attributable to Plutonium Recycle in LWRs.

generation costs are in levelized mid-1974 mills/KwHe, which means that the effect of long-run inflation has been taken into account. In this table one notes immediately the traditional higher capital and lower fuel costs for the nuclear systems as opposed to the fossil systems. Among the fossil systems the fluidized bed system seems to have both the lowest capital cost and electric generation costs, while among the nuclear systems the HTGR system, while exhibiting slightly higher capital cost than the LWR system, has (marginally) the lowest electric generation cost due to its more efficient utilization of scarce uranium resources. Using the base-case assumptions, the nuclear systems show a clear cost advantage over the fossil system due to the currently existing high prices of coal and residual fuel oil.

The base-case assumptions selected were certain to be controversial no matter what particular values were chosen. While ERDA analysts are projecting capital cost reductions for nuclear power plants in the future due to learning effects and economies of scale (see, e.g., References (6) and (139)), other analysts are collecting data which show that the capital cost of nuclear power plants has increased dramatically in recent years (see, e.g., Reference (169)). Further, evidence exists which argues that the OPEC cartel price is considerably below the current world price for oil, and that the current price of coal is substantailly above the marginal cost of producing it (see e.g. References (31), (57), and (60)). In view of these controversies and instabilities, and the inevitable uncertainties in conditions in the electric-power industry of the future of which they are a product, we explored the impact of varying some of the parameter values assumed for the base-case over ranges wide enough to include alternative values representative of those found in the literature. Various alternative assumptions about capital cost escalations, future fuel fuel prices, capacity factors and power plant efficiencies led to the range of electric generation costs shown in Figure I-4. Note that no system has a lower electric generation cost than another under all possible circumstances. In fact, as pointed out in Section III-A, escalation in nuclear power plant construction costs over and above that for fossil power plants may negate the electric generation cost advantage for nuclear generation that was so visible in Figure I-3 .

While the future costs of electric generation by technologies that are now commercial (e.g. RFO, LWR, HTGR) are difficult to ascertain, those for technologies that are still under development (e.g. Fluidized-Bed, LMFBR) are even more difficult to estimate. In fact, the further a technology is from commercialization, the more uncertain are its ultimate cost and performance parameters. Additionally, in order for a technology to gain widespread acceptance, R & D funds must often be expended to improve the safety and reliability of currently commercial technologies (e.g. LWR). Projected R & D costs for the eight study systems are shown in Figure I-5. In the Table only R & D costs that can be directly attributed to a particular system--i.e. mostly those spent on the power plants themselves are included. Section III-8 considers R & D categories that can impact on several systems, e.g. uranium mining. One notes immediately the relatively large expenditure and long time span projected for the LMFBR program.

Figure I-4: Range of Electric Generation Costs due to Plausible Variations from Base-Case Parameter Values



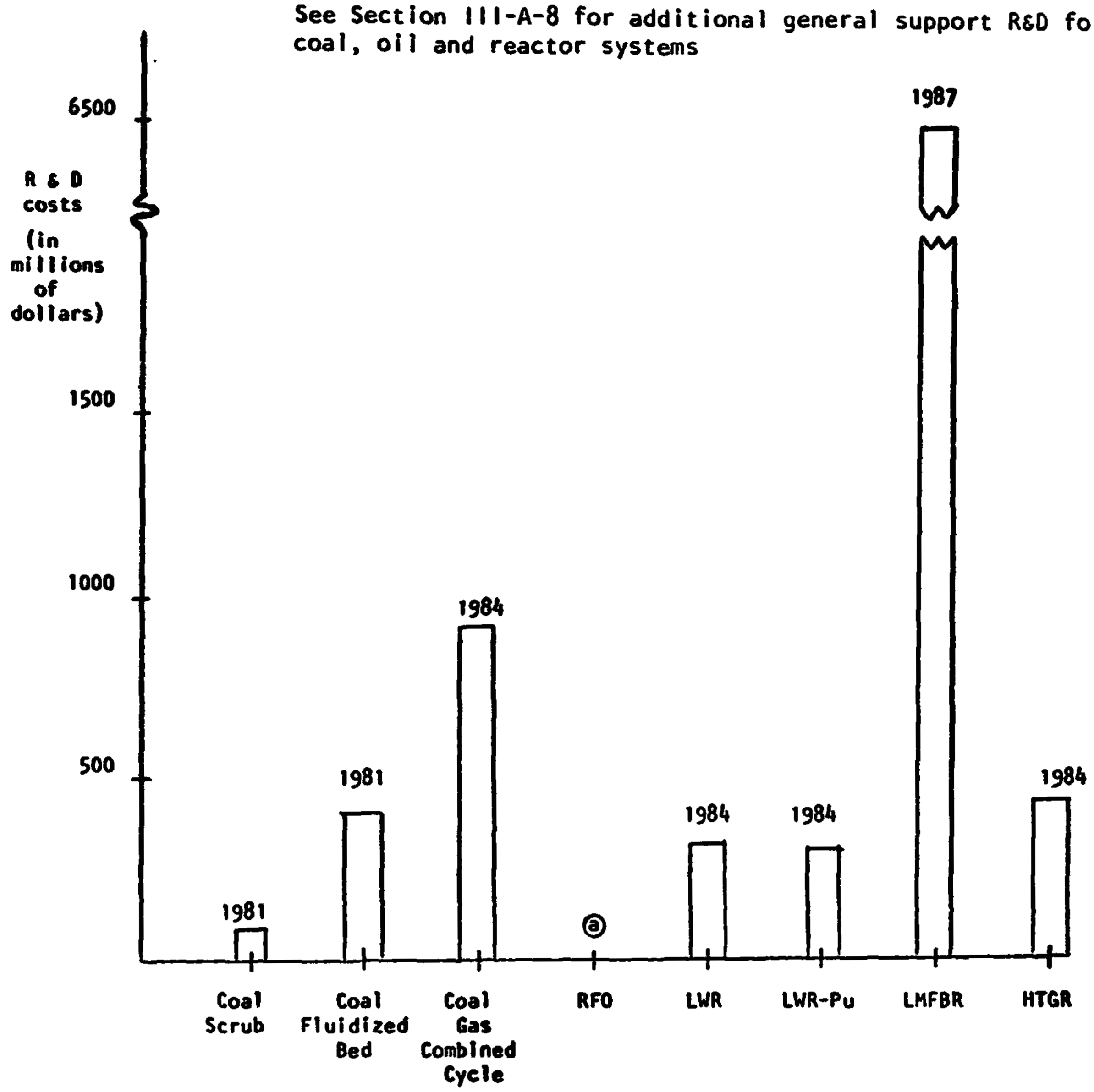
Varied Parameters (for details see Section III-A)

- Capital costs - High end is 5% differential inflation to 1990 plant startup.
- Fuel costs - High end is 3% differential inflation to 1990 startup for coal.
- Plant (capacity) factors - nominal (0.75) to historic (~ 0.60)
- Power plant efficiencies - nominal to advanced.

Figure I-5: Projected R & D costs

See Table III-A-6.

See Section III-A-8 for additional general support R&D for coal, oil and reactor systems



a. See coal-scrub.

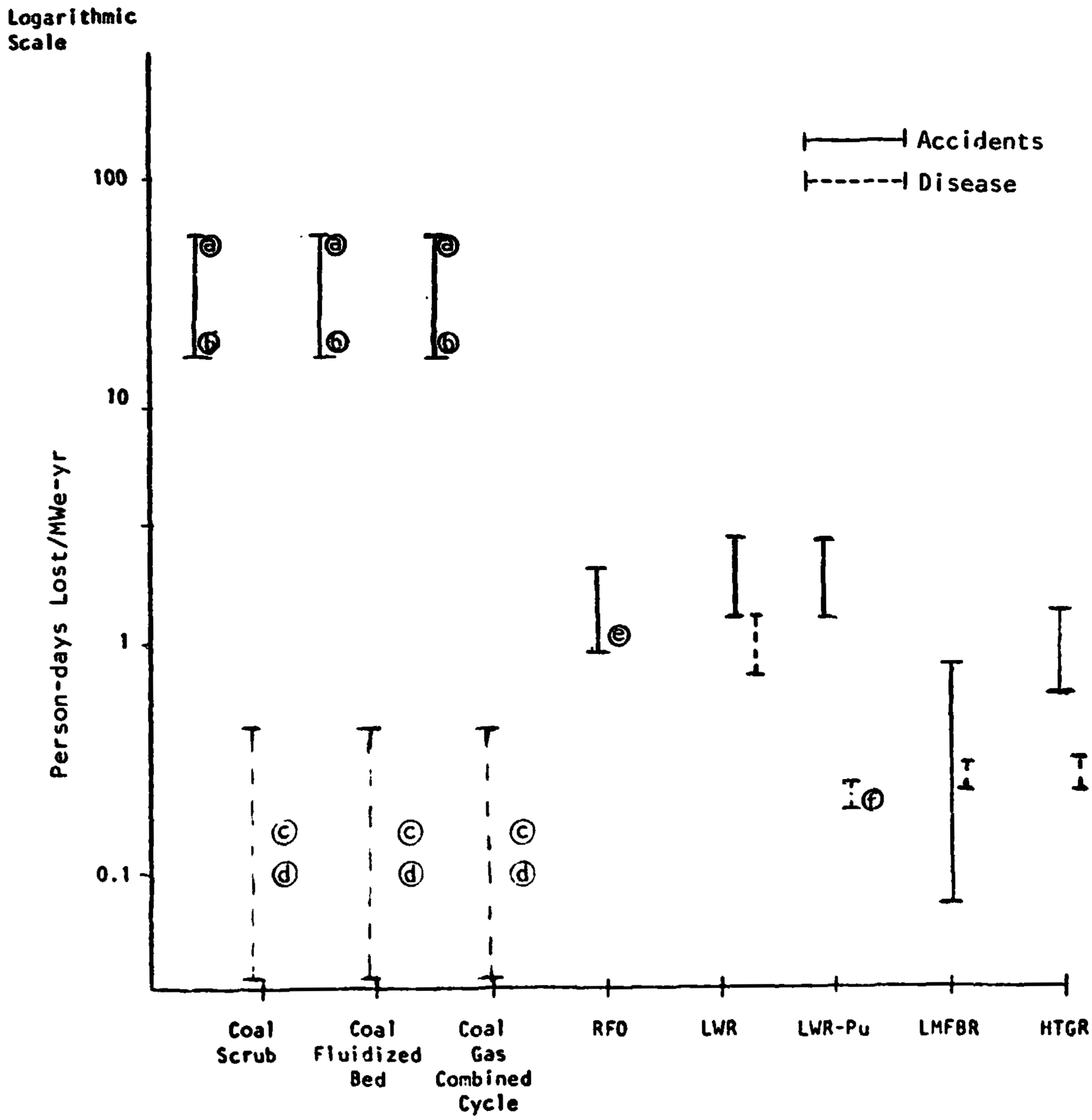
Comparisons: Environmental and Health Impacts

Figures I-6 - I-8 present the occupational and public health impacts, and the risks of catastrophic accidents at power plants. In some cases, the range of estimates is large due to uncertainties in the understanding of the processes involved, e.g., nuclear power plant risks. In other areas the ranges are large because of uncertainties about future regulations, e.g., dust levels in coal mines. In many cases where there is a seemingly narrow range, moreover, the reason is not that the impact is known with great accuracy, but rather than we found only one source in the literature dealing with that impact. The ranges shown are only a result of the scatter of values in the literature, not the result of an analysis of probability distribution. Thus, for the impacts of the HTGR, for example, the true ranges of uncertainty are probably much larger than the ranges for the LWR impacts. However, many more estimates have been made for the impacts of the LWR system. For a more detailed discussion of exactly what assumptions, uncertainties, and data went into developing the range of impacts for each system, see Chapter III and Appendices A-H.

It is evident from Figures I-6 and I-7 that future coal systems (fluidized bed and gasification) could have health impacts substantially below the level of the coal-scrubber system. Occupational impacts will fall mainly through better control of dust levels and accidents in coal mines, and public impacts will fall through smaller air emissions at power plants. The impact of the low-Btu gas/combined cycle coal system has the potential of being over 300 times less damaging to public health than presently operating coal-scrubber systems. Implementation of current dust standards and improving mine accident safety to the level of today's safest mines would result in a reduction by more than a factor of 10 in the damage to workers' health.

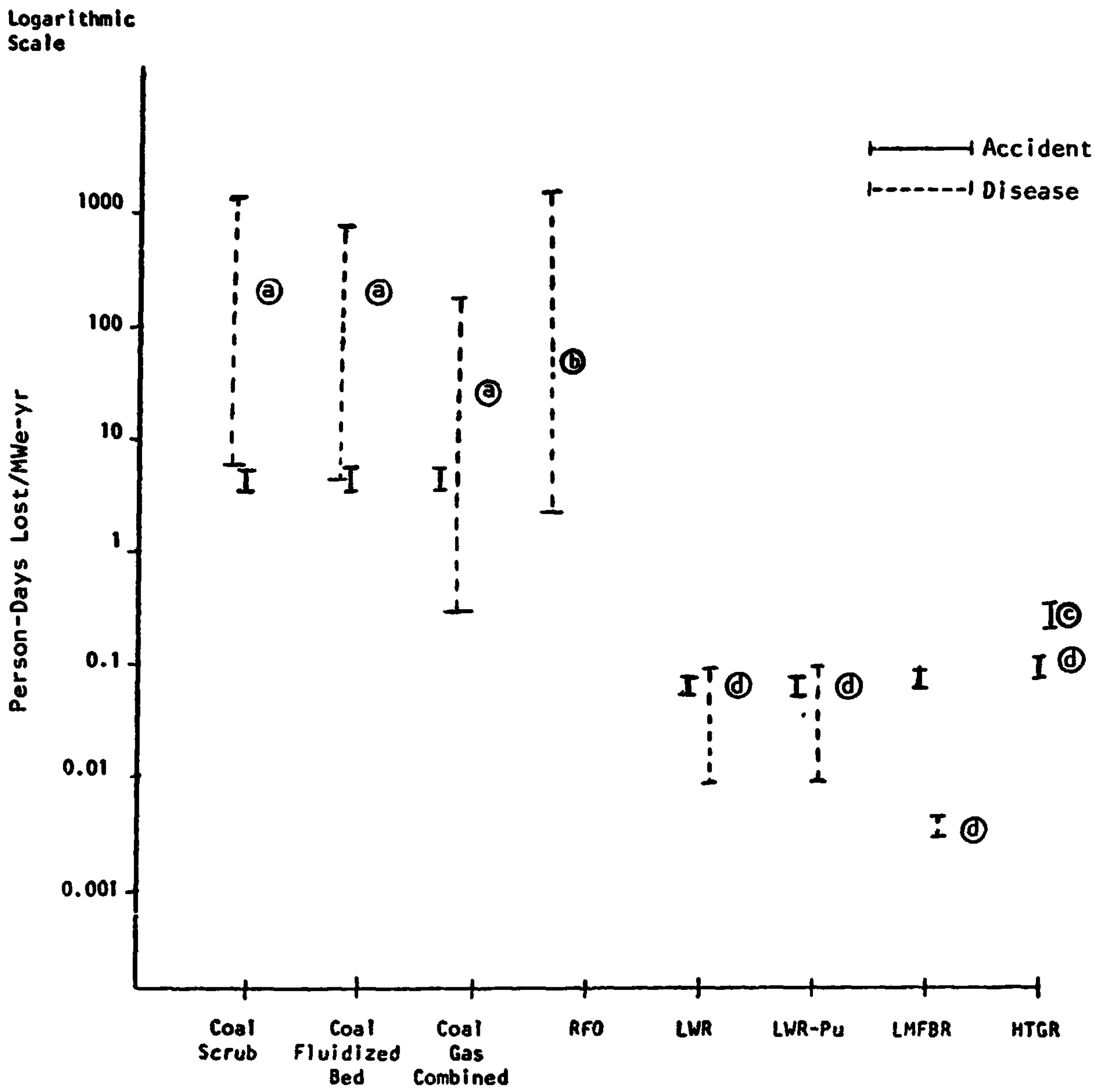
Nuclear systems do not seem to have a chance for such a spectacular improvement in routine impacts, although, because of increased control of radioisotopes at

Figure I-6: Occupational Impacts (3)



a. Upper part of range is primarily based on current average accident rates in coal mines.
b. Lower impacts can be achieved if the average accident rates in coal mines were to approach the rates in safest present mines.
c. This range represents the impact if present dust level regulations are enforced.
d. See Appendix A-3 for disease rates in present mines.
e. No occupational diseases have been identified here for RFO.
f. Could be thought of as the best possible for LWR as well.
g. 6000 person-days lost (PDL)/death whether premature deaths or acute deaths, 50 PDL/accident or illness and 100 PDL/cancer. These very different social impacts can be separated by reference to appendices.

Figure 1-7: Public Impact: Routine Emissions and Accidents



a. SOx pollution and whole body radiation dose only.

b. No public accidents identified for RFO.

c. Includes the global dose from Kr-85 and H-3. See Appendix.

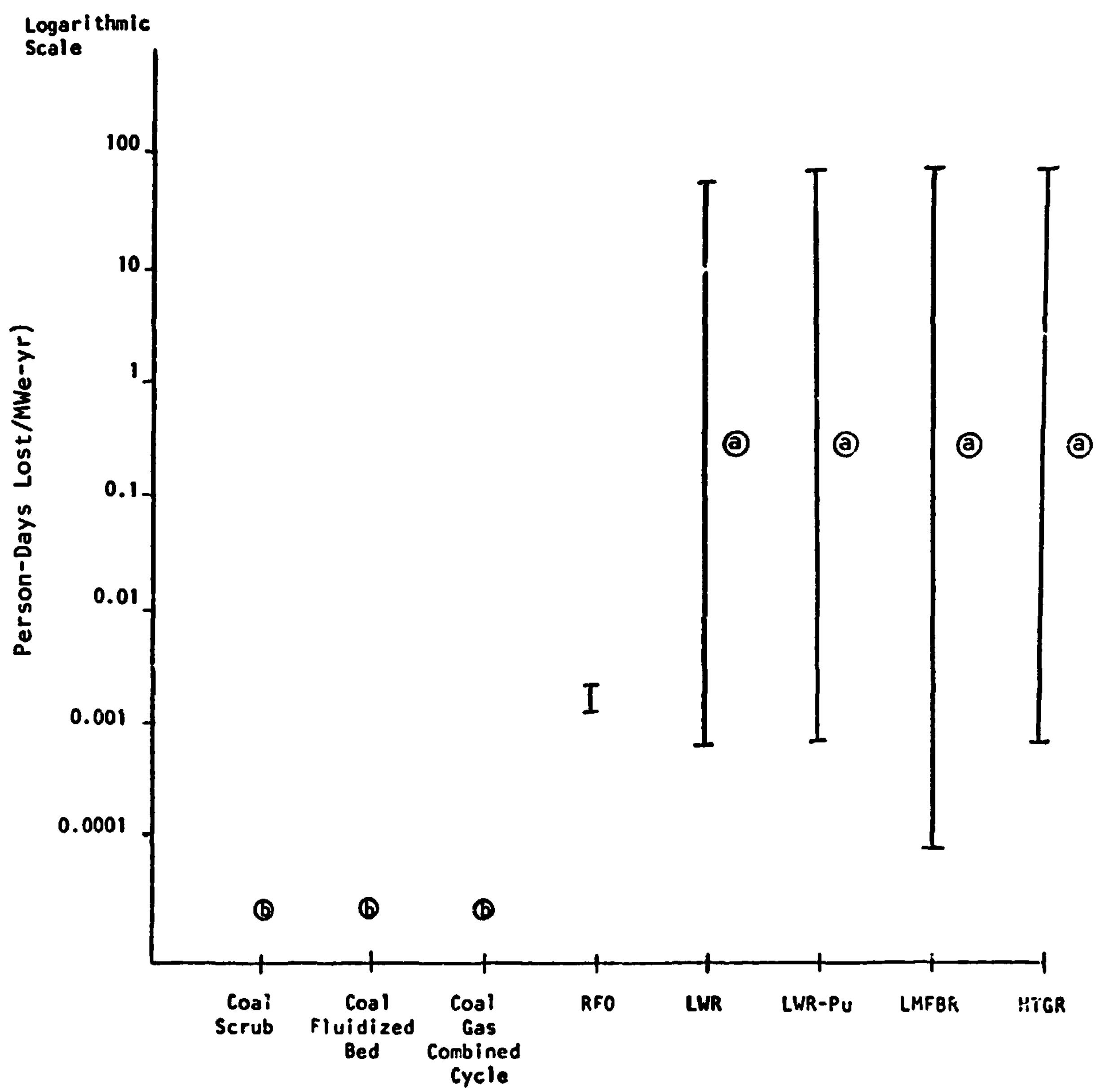
d. Health impacts of long-term storage or disposal considered to be zero due to current lack of data in this area.

reprocessing plants and less uranium mining (e.g., in the LMFBR cycle), the total routine impacts can be lessened in future applications.

Only the residual fuel oil (RFO) system competes at all with nuclear systems on the basis of routine impacts, at present. However, future coal systems will narrow the gap between the magnitude of nuclear and coal routine impacts considerably. In addition, coal systems do not seem to have the potential for major impact through large accidents, as do nuclear systems and RFO (the event of concern with RFO being major fires under inversion conditions). (See Figure I-8, which presents only the impacts of deaths from large accidents at power plants.) If nuclear accidents are as infrequent and low in consequence as indicated by the low end of the ranges in Figure I-8, the average impact of these accidents would not add much to the total impact. If, however, the accident risk is at the higher end of these ranges, the result of adding in the average impact would be to place nuclear and the best coal systems on a rough par with each other. There are, of course, other impacts to be considered and there are severe problems that result from the differences in the temporal, geographic and demographic distributions of impacts in different systems. See Chapter III and the Appendices for a more complete discussion.

To summarize: coal systems are becoming safer for workers and cleaner for everyone, but not to the level of nuclear systems. Nuclear systems, however, have a risk of large accidents which makes the total impact from nuclear power uncertain, but potentially as great or greater as the impact from the best fossil systems.

Figure 1-8: Societal Risk at Power Plant: Large Accidents



a. At 6000 days per death. This includes no accounting of the days lost to injury, illness, genetic effects, blackmail, diversion or sabotage.

b. No large accidents have been associated with coal plants.

Chapter II <u>TECHNICAL DESCRIPTIONS</u>

This chapter presents the technical characteristics and present level of development in the eight systems picked for detailed study. There are four fossil and four nuclear systems in this group and summary of the important technical parameters are presented at the end of the chapter in Tables II-1 and II-2.

Fossil Systems:

Coal Systems

Steam conversion and wet lime flue-gas desulfurization (coal-scrub)

Fluidized-bed conversion with sulfur recovery

Low-Btu gasification/combined-cycle combustion (C-C. system)

Residual Fuel Oil with steam conversion and wet lime flue-gas desulfurization (RFO)

Nuclear Systems:

Light-Water Reactor (LWR)

Light-Water Reactor with plutonium recycle (LWR-Pu)

Liquid Metal Fast Breeder Reactor (LMFBR)

High Temperature Gas Cooled Reactor (HTGR)

COAL SYSTEMS

We first describe the fuel cycle necessary to prepare coal for use at the three alternative coal-based power plants we have selected for study.

In this study we consider two alternative sources for coal: (1) Northern Appalachian deep mines and (2) Northwestern surface mines. The occupational health and subsidence problems associated with deep mines, and the land damage/reclamation problems associated with surface mines are tabulated separately. However, once the coal is mined it is aggregated, for the purposes of this study, into a single "national average coal." After extraction, this "national average coal" is transported (usually a short distance by truck or conveyor) to a processing plant where it is crushed and cleaned. The clean coal is then typically transported by train several hundred miles to the power plant. For further details on the coal fuel cycle see e.g., references (1), (2), (3), and (7).

A major problem with the coal-fired electric generation plants of the past has been the excessive amount of sulfur oxides that these plants generate. These sulfur emmissions have been shown to have detrimental environmental and health effects. In a coal-based system sulfur can be removed before, during or after combustion. Each of the coal-based systems we have selected for analysis is designed to remove the sulfur at one of these three stages: stack-gas cleanup, after combustion; fluidized-bed combustion, during combustion; and coal gasification, before combustion.

Coal with Lime Scrubber Flue Gas Desulfurization

This alternative involves the use of a conventional coal-fired steam-cycle plant with removal of sulfur dioxide from the stack gas. Electric generation from a coal-fired steam cycle is a mature technology. In modern plants the combustion of coal in a boiler is used to raise steam at 1100° F and 3800 psig. This steam is partially expanded through a turbine that drives an electric generator. The steam is then sent back to the boiler for reheat to 1100° F (now at lower pressure) and expanded through another turbine and condensed and cooled to about 100°F. The thermal efficiency of this system is about 37% (accounting for wet cooling towers and SO_2 removal) and is not expected to improve very much in the future; the metals currently used are near their metallurgical limit, and metals capable of withstanding more severe steam conditions are too costly and have a limited lifetime (Ref. (6)).

The major problem with removing sulfur from the stack gas is that a large fraction of a small concentration of SO_2 must be removed from large volumes of stack gas. There are dozens of flue-gas desulfurization processes under development. A recent report of the Commission on Natural Resources of the National Academies of Science and Engineering (Ref. (15)) contains a critical assessment of the development status of these alternative processes. This report first notes that, of all the proposed flue gas desulfurization systems, only the lime and limestone scrubbing systems have been operated successfully on a commercial scale. Secondly, it is concluded that lime scrubbing is the most reliable system at this time. Therefore, we have selected the lime scrubber flue-gas desulfurization system for inclusion in this study.

In the lime scrubber process about 90% of the sulfur in the stack gas is absorbed into a lime slurry. One drawback of this process is that a large amount of sludge is generated and must be disposed of. Although methods for sludge disposal are being studied (e.g. Ref. (90)), the long term solution to this problem may be the successful development of regenerative flue gas desulfurization processes (Ref. (15)).

Coal with Fludized-Bed Combustion

In fluidized-bed combustion sulfur is removed during the combustion process itself. Air is passed upwards through a bed of granular lime or ash creating an air suspension of these non-combustible materials. This air also serves as combustion air for crushed or finely ground coal which is injected near the base of a fluidized bed. Heat transfer surfaces are immersed in the bed allowing improved heat transfer, high volumetric heat release, and relatively low operating temperatures of about 1600 to 1800 degrees F. Low operating temperatures lead to reduced nitrogen oxide emmissions as compared to conventional boilers, and burning coal in the presence of a sulfur acceptor such as limestone or dolomite promises to effectively remove up to 95% of the sulfur in the coal during combustion.

Both atmospheric (References (97) and (98)) and pressurized (References (13), (94) and (96)) fluidized-bed boiler concepts are being developed. Atmosperic systems would replace conventional boilers, while pressurized systems potentiallv operating at pressures in excess of 20 atmospheres promise thermal efficiencies as high as 45%. We have selected the Westinghouse 635-Mwe pressurized fluidized-bed boiler (References (13), (94), and (96)) for analysis, as it promises higher efficiencies in the long run (i.e. in the time frame specified for this study) than the atmospheric systems and the Westinghouse preliminary design studies of the system (References (13), (94) and (96)) include data thought to be representative of proposed fluidized-bed systems. The Westinghouse system operates at 1750 degrees F. and 10 atmospheres, with an initial thermal efficiency of 37% (including provision for a wet cooling tower).

One final point needs clarification. Westinghouse refers to its design as a combined-cycle system. Before the flue gases are released to the atmosphere, they are cleansed of particulates by cyclones and aerodyne-type dust collectors and (still at 1600° F. and 10 atms.) expanded through a gas turbine. In fact this gas turbine supplies 24% of the system's maximum 635-Mwe output power. In this system, the steam and expander turbine cycles are run in parallel. In this report, a 'combined-cycle' system refers to a system in which the gas and steam turbines are run in series, with the steam turbine using the exhaust of the gas combustion turbine as input.

Low-Btu Coal Gasification/Combined-Cycle System

This system involves a two stage process in which coal is converted to a low-Btu (typically 120 to 200 Btu/Scf) gas, which is subsequently used as fuel for a combined-cycle power system, Many methods for producing low-Btu gas from coal have been proposed (Refs. (105), (106), (107), (108), and (109)). After impurities have been removed, the product of the gasification process is a mixture of carbon monoxide, carbon dioxide, hydrogen, nitrogen and methane. Sulfur can be removed from the gas stream by a number of commercial methods. However, these processes are only effective at temperatures up to about 600° F. (Ref. (110)). Of all the proposed low-Btu gasification processes, only the Lurgi and Ignifluid processes have had significant commercial application. Since ample data are available for the Lurgi process and because it represents a benchmark for advanced systems, we have selected it for inclusion in our study.

In the Lurgi process (Refs. (106), (107), (108), (111), and (112)) coal is fed intermittently through a lock hopper into a fixed bed at about 20 atmospheres and 1200-1600° F. and gasified with air and steam. The raw gas is then scrubbed to remove coal dust, alkali and chlorine. After cooling, the H_2S is removed from the gas stream by an alkalized wash and converted into elemental sulfur. The product gas is at about 200° F. and 17 atms. The thermal efficiency of this process is about 75.8% and sulfur removal efficiencies as high as 99.7% (Ref. (3)) are expected.

In this system waste heat from a gas turbine is used as a heat source for a steam cycle. In 1972, several hundred-Mwe of natural gas fired combined-cycle systems were in use, and 2500-Mwe were on order (Ref. (40)). The thermal efficiency of a combined-cycle system is limited largely by the achievable turbine inlet temperature. The system considered here has a turbine inlet temperature of about 2200° F., which gives a combined-cycle thermal efficiency of 47%. Turbine inlet temperatures of 3100^{o}F (leading ·o thermal efficiencies of 57.7%) are thought to be possible in the foreseeable future (Refs. 23, 103A). For our overall coal-gasification/combined cycle power plant the thermal efficiency is about 37%.

Residual Fuel Oil Fired Plant with Stack Gas Cleanup

This alternative is identical to the coal-fired plant with stack gas cleanup described above, except for minor differences due to the fact that residual fuel oil replaces coal as the primary fuel. With oil, which is less bulky than coal, less storage space is required, and following combustion there is virtually no ash to be disposed of. However, the fuel cycle required to prepare the oil for use at the power plant is obviously quite different from the coal fuel cycle and will be described here.

In this report we will consider two alternative sources of oil for electric power generation: (1) domestic offshore oil which is assumed to be transported to the refinery by pipeline and (2) foreign crude which is assumed to be transported to the refinery by oil tanker. At the refinery the crude is transformed into a number of petroleum products including gasoline, distillate fuel oil and residual fuel oil. Residual fuel oil is then typically transported to the power plant by pipeline. For further discussion of the oil fuel cycle see the references given at the end of the coal fuel cycle description.

Summary data is shown in Table II-1 for the fossil systems.

LWR

The designation of light-water reactor in this study includes both boiling-water (BWR) and pressurized-water (PWR) reactor systems. Most of the costs and impacts are similar for the two systems, and we combine them into a single table here except in those categories where there is a significant difference.

LWRs rely for their energy production mainly on the fissile isotope of uranium, U-235, which fissions best with thermal (low energy) neutrons.* U-235 contains pound for pound about 2.5 million times as much energy as coal, but U-235 makes up only about 0.7% of natural uranium, and uranium makes up only about 0.17% of the sandstone ore being mined today. Accordingly, the ore requirement is not trivial. For use in a LWR, the uranium ore is 1/35 of the weight of coal for equivalent amount of energy at the power plant. This ore is processed in uranium mills to extract uranium oxide (U_3O_8). The U_3O_8 is sent to a conversion plant which converts it into the gas, UF_6, for input to the gaseous-diffusion enrichment plants. At the enrichment plants the percentage of U-235 is increased to 2-4% and the depleted uranium (or tails), containing 0.25% U-235 and 99.75% U-238, is stored on site. The enriched uranium is then fabricated into fuel rods of UO_2 which are loaded into the reactor. After 3 to 4 years in the reactor the rods, now containing "spent" fuel, are sent to fuel reprocessing plants where, after chemical processing, three separate streams of material emerge. The first

* A fissile material will readily undergo fission and release energy when struck by a neutron. A fertile material undergoes fission much less readily but under some circumstances can capture a neutron and thereby be converted into a fissile material. Today's LWRs obtain about 80 percent of their energy from the fission of U-235 and 20 percent from the coincidental fission of fertile U-238 and plutonium made from U-238.

stream consists of fission products and other radioactive wastes which are sent to waste management facilities. Another stream consists of the remaining uranium which now is only slightly enriched over natural uranium and is sent back to the conversion plant in parallel to the incoming stream of natural uranium. The third stream is plutonium-239 produced in the reactor by the capture of neutrons in fertile U-238. This plutonium is stored for possible future recycling in LWRs, or in breeder reactors.

LWR power plants are commercially available now, and within the time period of this study their design is likely to change significantly only in the areas of increased environmental and safety equipment. The fuel-cycle facilities from mining to power plant are also well developed and subject to only slight change in the next decades, with the exception of enrichment. (Research is being done on methods of enrichment--e.g., laser separation--which potentially could lower the capital and energy requirements of enrichment significantly. See chapter III.) However, the two steps after the power plant, reprocessing and waste management, do not exist in commercial form today and will have to be developed quickly in order to support a large capacity of LWRs. There is no operating fuel reprocessing plant at this time, although one is being built and another undergoing modification. Spent fuel rods are beginning to exert a burden on storage facilities. Previously reprocessed waste is being stored in temporary facilities until a decision is made about the type of management scheme to be followed. The expectation of the industry and the responsible government agencies is that these problems will be solved by the end of this decade or shortly thereafter. (References 6,9, 19,21,45,143.)

LWR with Plutonium Recycle

A LWR can be operated with several different mixtures of plutonium and uranium fuels, and there is an economic incentive to utilize the plutonium which is produced in uranium-fueled LWRs to reduce the requirement for enriched uranium input.

We have chosen the type of plutonium-recycle system in which some of the enriched uranium oxide fuel rods in the LWRs have been replaced with rods containing both PuO_2 and natural UO_2. This seems to be the most likely system to be used in the time period considered in this study.

There are significant differences between a LWR power system with and without plutonium recycle. The economic factors affecting the value of plutonium are extremely complicated and subject to wide interpretation. With plutonium recycle, the major environmental differences result from the increased effect of leaks associated with the larger amounts of plutonium in the cycle, and from the increased availability of the plutonium in forms attractive for diversion. If recycle is instituted, mixed oxide fabrication plants will have to be built.

The decision whether or not to initiate plutonium recycle in LWRs was originally scheduled to be made in 1975 but has been delayed for further study until at least 1978. (References 3,12, 141,163,164.)

LMFBR

The LMFBR is part of a nuclear power system which differs in several important respects from LWR systems. It has different economic and environmental characteristics and is in a much earlier stage of development.

The basic difference between a breeder reactor and the "converter" type of reactor represented by the LWR is that a much larger percentage of the total energy potentially available in the uranium can be utilized in breeder reactors. Much more of the U-238 is converted to plutonium and, potentially, a breeder system can generate all its fuel from U-238 and be completely independent of U-235.

No enrichment capacity is necessary for a breeder system if the breeding doubling time* roughly corresponds to the doubling time for the construction of new generating capacity. However, the first breeders will have doubling times much longer than the 10 years or less thought to be optimum in the industry. At first, the initial and reload cores of plutonium will be fabricated from the plutonium produced and stored in the LWR cycle. Indeed, the economics of breeders and LWRs cannot be entirely separated; *i.e.*, there is some additional incentive for building more LWRs because some of the plutonium produced in LWRs will be bought for use in the breeders. The amount of uranium needed in a LMFBR (as a source of U-238 for breeding with plutonium) is much

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* The doubling time is the time it takes to double the inventory of fissile material including the material circulating in the fuel cycle. Consequently it is a function not only of the reactor and fuel characteristics but also of the cooling period, processing time and other fuel cycle parameters.

smaller than the requirement of LWRs and other converters. For some time to come, the needs of LMFBRs probably will be obtained from the depleted natural uranium tails at enrichment plants. However, if breeders become the major nuclear technology and remain so, new uranium will eventually have to be mined to supply them with U-238. Thus we have counted the environmental effect of mining and milling the LMFBR's small uranium requirement against the breeder program, as have several other studies.

Fuel fabrication plants will be similar to the mixed oxide plants required for a LWR recycle system. Fuel reprocessing plants, although similar to those for LWRs, will have to be more carefully managed; this is so because to maximize breeding ratio, fuel discharged from LMFBRs will not be stored as long as is LWR fuel before reprocessing, so it will be more radioactive. In addition there are larger amounts of plutonium at each step than in either the LWR or LWR-plutonium-recycle systems.

Research in fast reactor fuels for use in commercial plants will be undertaken at the Fast Flux Test Facility (FFTF) which is a government funded test reactor rated at 400-Mwth and scheduled for operation in 1977. The first demonstration reactor, which follows the operation of several smaller special-purpose fast reactors, will be built for TVA at Clinch River. This reactor is now planned to begin operation in 1982. It will be rated at 350-Mwe, operate at about 36% thermal efficiency, and have a very long doubling time--perhaps 60 years or more. The first full-scale commercial plants are planned to come into operation about 1990 and be at least 1300-Mwe. These plants are expected to have about a 40% thermal efficiency and a 25 year doubling time. Decreased doubling times will probably require advanced oxide, nitride or carbide fuels which are unlikely to have much impact in the time period being considered in this study. (References 6, 21, 43, 45, 170-172, 178.)

HTGR

The HTGR is a helium-cooled, advanced-converter reactor (not a breeder), which operates on the uranium-thorium fuel cycle. Highly enriched uranium (93.5% fissile) is used in combination with the fertile material, thorium 232, in a graphite matrix core. The helium coolant is circulated at high pressure and the temperatures potentially attainable are high enough to reach 40% thermal efficiency with simple steam conversion.

Uranium 233 is formed when thorium 232 captures a neutron in the core. Since the thorium and uranium fuel particles in the reactor are physically separate this U-233 can be separated easily at the reprocessing plant. Thus there are six separate streams which emerge from the reprocessing plant. One is unreacted U-235 which is sent back to the fabrication plant for recycle. The second, newly formed U-233, and the third, recycled U-233, are also sent back to the fabrication plant. The fourth is the fission products and other radioactive wastes which are sent to the waste management facilities. The fifth is unreacted thorium which is now very radioactive and will be disposed of in waste management facilities.* The sixth is U-235 and U-238 which has passed through the reactor a second time and now is unsuitable for further use due to low concentration and poison buildup (U-236) and must be send to waste management.

In addition, although there is relatively little U-238 in the HTGR cycle the small amount does produce some plutonium by neutron capture. At the present time it does not seem economical to separate out this plutonium and so it is left

* The thorium could be stored for about 15 years until the radioactivity becomes low enough for recycle and manual fuel fabrication but this is not planned.

in the waste streams. Thus, although there is much less plutonium produced in HTGRs than in LWRs there is substantially more in the final waste.*

The amount of enrichment required for an HTGR is actually less than for a LWR even though the level of enrichment is so much higher. This results from the much smaller total of uranium requirement. The fuel fabrication and reprocessing facilities are very different from those used for LWRs or LMFBRs and, of course, only the HTGRs require thorium mining and milling. The thorium requirements, however, are very modest.

A prototype 40-Mwe HTGR was operated at Peach Bottom, Penn. from 1967 until shutdown in 1974. In 1974 power testing began at the Fort St. Vrain 330-Mwe demonstration HTGR in Colorado. General Atomic is offering 770 and 1160-Mwe plants for sale and several utilities have placed orders. However, recently, there have been several cancellations and deferrals and there are no operating fuel fabrication or reprocessing plants for the HTGR, although small demonstration plants are planned to begin operation in 1979. The successful entry of HTGRs into the utility market will depend on the performance of the demonstration reactor, the establishment of a complete fuel cycle, the status of the nuclear industry in general, and to some extent on the willingness of the government to provide research and develo;emnt assistance to the effort which, to date, has been largely funded by private industry.**

* This plutonium, however, has a smaller fraction of long-lived Plutonium-239 and thus after several hundred years the activity of plutonium from HTGRs is less.

** General Atomic, who is the commercial supplier of HTGR, has recently announced that they will not be supplying HTGRs (Nuclear News, Nov. 75).

HTGRs could potentially operate at a temperature high enough to be used as a source of process heat for industrial applications or hydrogen generation. Alternately, with the application of a closed-cycle gas turbine plus a vapor bottoming cycle the thermal efficiency for electricity generation could potentially reach 50%. However, with present materials these high temperatures are difficult to use and still achieve a high degree of component safety and reliability. These applications will probably not have a significant impact during the time period considered by this study. (References 3,6,21,179-185)

Summary data is shown in Table II-2 for the nuclear systems.

Table II-1

Technical Specifications

Fossil Power Plants

	Coal-Steam with Scrubber	Coal Fluidized-Bed	Coal Low-Btu Gas/ Combined-Cycle	Oil-Steam with Scrubber
Thermal Efficiency % a	37 - 39	36 - 43	29 - 51 f	37 - 39
Critical Temperature °C	1000 - 1100 b	1600 - 1800 d	1800 - 3100 g	1000 - 1100 b
Size Mwe	100 c	30 e	600 h	See coal-steam with scrubber
Sulfur Removal % a	80 - 90	90 - 95	98 - 99.7	80 - 90

a. See text and appendices.

b. Steam temperature.

c. Lime scrubber, 830-Mwe being built (15)

d. Combustion temperature (6).

e. Atmospheric plant to begin operation June, 1975 (215).

f. 39 - 57% combustion, 75 - 90% gasifier.

g. Gas turbine inlet temperature (23).

h. Combined-cycle plant only (30). A 170-Mwe plant utilizing Lurgi low-Btu gasification is operating in Germany (113a).

Table II-2

Technical Specifications

Nuclear Power Plants

	LWR	LWR with Pu Recycle	LMFBR	HTGR
Thermal Efficiency %	31 - 34		(f) 36 - 40 (g)	39 (i)
Critical Temperature °C (a)	320 - PWR 285 - BWR		(f) 535 - 566 (g)	755 (i)
Size Mwe	1100	430 (e)	350 (f)	330 (i)
Uranium Utilization % (b) (c) (d)	0.55 0.51	0.73 0.69	(h) 77.0 41.0	1.06 0.95

a. Coolant outlet temperatures

b. 0.25% Tails assay
   $7.6\ (10)^{10}$ Btu/Kg-U at 100 % utilization
   75% capacity
   Change of +/- .05% in Tails assay results in a corresponding change of about +/- 10% in the values listed for LWR and HTGR (11)

c. Top numbers in row base on yearly load

d. Bottom numbers in row base on $\frac{\text{Initial core + (yearly load x 29)}}{30}$

e. San Onofre experiment 1970-1973 (12)

f. Clinch River Breeder Reactor (95)

g. Projections in W-1535 (6)

h. Ref. 3 & 6

i. Ft. St. Vrain Reactor (185)

CHAPTER III COSTS AND IMPACTS: DISCUSSION AND SENSITIVITY ANALYSIS

Introduction

This chapter compares and contrasts the eight reference power systems. We have chosen to discuss a few important costs and impacts in each of the fuel cycle steps in order to illustrate the range of uncertainties and to explore the possible implications of these uncertainties. The reader is referred to Appendices A - H for specific estimates of the economic, resource, environmental and health impacts of the eight power systems.

We have assigned a total primary efficiency to each of the reference systems. If the total efficiency of these fuel cycles changes, the impacts at each of the steps will change as well. For some types of impacts the change will be exactly proportional. For example, a change in power plant efficiency will directly affect emissions at the plant and the amount of mining required per Mwe-yr. However, some types of impacts do not change in a linear fashion with changes in efficiency. These types of impacts are a function of both the efficiency and the size of individual facilities. For example, the land used for a million-MT/yr mine is not exactly one half of the land used at a mine with twice this capacity. However, there are significant uncertainties in the published data, large variations in regional practice and a range in the characteristics of the technologies which all tend to broaden the range of estimates for a particular cost or impact. Except for certain costs, we have not tried to correct for the scaling problems and believe that the range of estimates within the final tables (A-H) would span any changes due to non-linear scaling. For example, if a power plant is reported in the literature to have a power rating of 1000-Mwe (P), an annual load factor of 75% (L) and an emission of xMT/yr, we have reported the emissions as x/LP or x/750 per Mwe-yr. If the power plant construction material is y MT, then we have reported this material requirement as y/750 Mwe per 30 yr lifetime (y/22500 Mwe-yr). The difference in these two examples is that the first item is relatively proportional to energy production, while the second is used once in the 30 year lifetime of the plant.

III-A: Costs and Resource Utilization

III-A-1: Introduction

In this section we: (1) summarize the major implications of the cost and resource utilization data collected for the eight electric generation systems selected for study, (2) explore the sensitivity of this data--particularly electric generation costs - to changes in the base case economic assumptions, and (3) report on the R & D costs estimated to be required to bring the selected systems to commercial realization. For ease of exposition, the present discussion does not enumerate all of the technical details and assumptions involved in the data normalization process. The interested reader may find this information as well as all the basic data in the Appendix. In collecting these data each electric generation system was divided into five general processing stages: harvesting fuels, upgrading fuels, transportation of fuels, conversion to electricity and management of final waste. The waste streams in each of these processing stages are also accounted for in addition to final wastes. It is therefore possible to assess the economic and resource utilization impact at each of these stages for each system as well as to compare alternative systems within this convenient framework. The objective of the sensitivity analysis presented here is not to explore the implications of the entire range of possible values for each economic parameter, but rather to analyze the effects of changes in the values of a limited number of parameters whose impact changes significantly within a plausible (according to documented analysis by qualified experts) range of possible values.

Traditionally, the major components of the cost of electric generation have been fuel cost, and power plant capital and O & M costs. Power plant efficiency, capacity factor and size, as well as basic economic indicators such as the projected inflation and interest rates are also relevant. Many ways of combining these components into a measure indicative of the actual cost of electric generation have been proposed. The method used to accomplish this task here was developed at the Jet Propulsion Laboratory (JPL) and is thought to be typical of the type of calculation made by electric utilities in assessing the economic merits of alternative electric-power generation systems and therefore appropriate for assessing the commercial competitiveness of these technologies. Details on the methods of calculation are left for the Appendix and the justification for it to Ref. (28).

Although the terms inflation and escalation have been defined in different ways by various authors, in this report inflation is defined as the rate of increase in the overall price level in the economy (as perhaps best indicated by increases in the consumers price index), while escalation in a particular industry refers to the rate of increase in the price level in that industry over and above the overall inflation rate in the economy. In the present application, for the base case, costs are calculated in levelized mid-1974 dollars (the term "levelized" refers to the fact that capital, O & M and fuel costs are input in mid-1974 dollars, but that the effect of long range inflation on these costs is considered) for initial commercial operation in about 1990. This is done by projecting escalation from the relatively easy to identify sources, and assuming that no escalation in other portions of the electric-power industry will occur. As the electric-power industry has recently experienced significant escalation from non-anticipated sources, alternative escalation assumptions are included in our sensitivity analysis.

To aid in projecting escalation in the electric-power industry,data on the cost of building and operating new energy facilities (at each fuel conversion stage)have been collected. Construction manpower requirements for these facilities were also compiled according to four general categories defined in a recent study by the Bechtel Corporation (8), while operational manpower requirements were completely aggregated. An attempt was also made to assess the efficiency of resource utilization at each stage of each electric-generation system. Data on non-primary fuel energy requirements at each stage were also compiled. Construction material requirements were collected for five major categories defined in the Bechtel study (8), as were materials requirements necessary for operating sulfur removal systems for the coal fueled options. Three categories of land use were considered: (1) land temporarily committed and disturbed for the useful life of the facility, (2) land temporarily committed, bu' undisturbed and (3) land permanently committed (i.e not reclaimable even after the end the useful service life of the facility under current economic conditions). Finally, the quantity of water consumed (only water that is evaporated and therefore no longer assured of availability to the local water table was considered) was collected.

The next five subsections report on the significant resource utilizations and economic sensitivities of each conversion stage, while subsection 7 deals with some multiple sensitivity analyses. Finally, subsection 8 tabulates some estimated R & D requirements for the commercialization of the alternative electric-power generation systems.

III-A-2: Harvesting Fuels

Although all four of the reactor concepts considered in this report require natural uranium (U_3O_8) the amounts utilized vary significantly among the various systems. The biggest consumer is the LWR, for which about 154 MT of U_3O_8 must be mined and milled for each reactor year (a 1000-Mwe reactor operating at 75% capacity factor for one year). A LWR with Pu recycle requires about 80% of this amount, a HTGR, a little more than half and a LMFBR less than 1% (actually for the first LMFBRs no uranium would be mined, as the accumulated enrichment tails from LWR fuel processing would be used as the source of fertile material). The utilization by a given reactor type of nonfuel resources, such as chemicals for milling uranium or manpower, during the harvesting of fuels stage is roughly proportional to its relative annual uranium requirement (although the HTGR requires the mining of a small amount of thorium). Even for LWRs, though, the amount of nonfuel resource consumption for mining and milling uranium is very small--typically less than 1%--of the resource utilization at the power plant, except for land use (i.e., land disturbed by the surface mining of uranium) and operational manpower (e.g., miners required to extract uranium and various mine administrative personnel). Further, for a LWR the cost of mining U_3O_8 is only roughly 25% of the total fuel cycle cost, which is itself only about 30% of the cost of producing electricity with LWRs.

Per unit of electrical output, nonfuel resource utilizaton for the mining of coal for use in the coal-based systems considered here is a significant fraction (usually >10%) of the nonfuel resource utilization at the power plant itself. Land use and operational and maintenance personnel are, again, the most significant nonfuel resource uses associated with mining, with about 2400 square meters affected by subsidence and 1600 man-hours required to mine the coal necessary to produce one megawatt-year of electricity for the base case (for which coal is obtained from Northern Appalachian underground mines). Alternatively, were the coal obtained from Northwestern surface mines, only 189 man-hours would be required to do the mining, and over 1700 square meters of land would be disrupted. The cost of mining coal currently makes up around 2/3rds of the price electric utilities pay for it (the remaining percentage being attributable to cleaning and transport). As the cost of coal is about 50% of the cost of producing electricity from it, electricity cost is very sensitive to coal cost for these systems.

For our base case of Outer Continental Shelf (OCS) production, oil extraction required a significant committment of nonfuel resources such as steel for platform, piping, and manpower. Residual fuel oil (RFO) is only one of many products that can be obtained from crude oil. This complicates any attempt to assign particular resource utilizations to specific refinery products. This problem was dealt with by calculating nonfuel resource utilizations as if the entire refinery output were RFO.

The contribution of the cost of raw fuel material to the overall cost of electricity generation is greatest for the residual fuel oil system, less for the coal systems and least for the nuclear systems. The land use for the extraction of the three types of natural resources are also orders of magnitude different, with oil (from the OCS) requiring a negligible amount of land disturbance (if the indirect impact on the sea shore from spills and aesthetics are ignored). Surface mining of uranium is a significant portion of the nuclear system land committment, but is still only about 5-10% of that disturbed by the amount of surface mining of coal required to produce an equivalent amount of electricity.

Although the contribution of the cost of uranium ore to the cost of nuclear power generation is not, in general, great relative to fossil fuel costs, it is a critical factor in determining the relative economics of the nuclear alternatives (see e.g., Derian and Bupp, (Ref. (177)). Further, since the prices of coal and RFO are significant contributors to the cost of operating the fossil-fueled electrical generation systems, an analysis of the sensitivity of all the systems to their respective raw fuel costs was performed and the results of this analysis are tabulated in Table III-A-1. The base case U_3O_8 price was determined by combining current ERDA assessment of U_3O_8 availability, with current estimates of the rate of buildup of nuclear generating capacity. The U_3O_8 (yellowcake) initial price is 14$/lb in mid-1974 dollars, and escalated as shown in Table E1 (note i). The low price case uses a more optimistic projection of U_3O_8 availability, while the high price case uses a less optimistic projection.

The base case coal and oil prices are the current prices paid by electric utilities for these fuels. The low coal case is based on the cost of coal production from new mines estimated by the Bureau of Mines (the so-called marginal cost of mining coal), while the high price case represents escalation (greater than general inflation) of the price of coal by 3% per year. The price of coal doubled from mid-1973 to 1974 and escalated over 20% during the second half of 1974, a trend that simply cannot continue. This escalation is based on the cost of coal in a liquefaction based economy toward the end of the century.

The $7.00/barrel price of RFO (which corresponds roughly to a $5.50/barrel f.o.b. Persian Gulf price) is based on what is thought by many to be the eventual OPEC cartel world oil price. The base RFO is $12/barrel and is current OPEC price.

Table III-A-1: Sensitivity of Electric Generation Costs to Fuel Price

Numbers given are electric generation costs in levelized mid-1974 mills/KwHe, but reflect projected conditions in the 1990 electric power industry. MBtu = million Btu

System	Fuel Price: Coal (a) Low 55¢/MBtu	Coal (a) Base 83.9¢/MBtu	Coal (a) High $134/MBtu	RFO (b) Low $1.11/MBtu	RFO (b) Base $1.93/MBtu	U_3O_8 (c) Low	U_3O_8 (c) Base	U_3O_8 (c) High
Coal-Scrub	26.6	31.7	40.7					
Fluidized-Bed	21.9	27.1	36.1					
Low-Btu/Combined-Cycle	25.8	30.9	39.9					
RFO				31.8	43.2			
LWR						20.6	22.7	26.7
LWR-Pu						19.9	21.3	24.6
LMFBR						21.9	21.7	21.1
HTGR						19.7	20.7	23.0

NOTES: Table III-A-1

a. The base case coal price represents the December, 1974, average paid by the electric utilities in mid-1974 dollars. Ref. (31) The high coal price represents escalation greater than general inflation in the base-case coal price at 3% per year until 1990. This produces an increase of 1.6 times the coal price when the 3% escalation is maintained until 1990, and is collapsed to mid-1974 dollars. The low coal price is based on recent Bureau of Mines estimates of the marginal cost of mining coal from new mines (Ref. (57) and (60)). It is assumed that half of the coal is mined in underground mines at \$9.82/ton (in mid-1974 dollars). Adding the cost of transport by improved methods (see Section III-A.4 for a discussion of cost of transport) and cleaning costs, it is assumed that this coal can be bought by power plants for \$12.00 a ton. The other half of the coal is assumed to come from large Northwestern strip mines at \$3.24/ton. It is further assumed that not all of this coal can be consumed in the West, so that long haul transport to the East is necessary. The total average price paid by utilities for this Western coal is, therefore, assumed to be \$8.00/ton. The deep mine coal (mostly Eastern) is assumed to have a heating value of 12,000/Btu/lb., while the Western coal is assumed to have a heating value of 8,000 Btu/lb., which yields a national average coal price of 55¢/M Btu. It is hard to imagine a lower average coal price than this in 1990.

b. The base case RFO price represents the average December, 1974, price paid by utilities for RFO adjusted to mid-1974 dollars. The low price represents the estimated OPEC cartel price of about \$7.00/barrel (see e.g., Ref. (229) and (230)).

c. The cumulative demands for U_3O_8 for all those U_3O_8 price scenarios were derived from the case D scenario given on page 53 of Ref. (11), assuming a tails assay of 0.25%. For the LWR case it was assumed that these would be the cumulative U_3O_8 demands. Although delays and cancellation of nuclear power plant construction have occurred since the formulation of this particular scenario, the LWR case does not assume Pu recycle, which offsets the decreased demands due to cancellations. For the LWR-Pu, LMFBR and HTGR systems, however, the scenario D cumulative U_3O_8 demand projections are discounted 20% due to delays and cancellations of nuclear power plant construction.

The U_3O_8 availability scenarios assumed for the base case were derived from the U_3O_8 availability data given on page 3 of Ref. (176). It was assumed that all the known reserves and estimated additional reserves could be produced on a timely basis at the prices given and further that the price of U_3O_8 would stabilize at around the year 2000 due either to the discovery of considerable additional low cost resources, as Ref. (145), (159) and (232) imply may be plausible, or to the significant commercialization of Breeder Reactors (of course, the non-existence of additional reserves would make the case for the Breeder stronger). U_3O_8 prices were derived by interfacing appropriate U_3O_8 demand and availability scenarios for a model reactor beginning commercial operation in 1990 and operating for 30 years. A more detailed calculation of the low, base and high nuclear electric costs are shown below* for a 1000 MWe plant for 30 year life and a 1990 plant startup. All costs are in millions of levelized mid-1974 dollars.

Details on how the price data were incorporated into the cost of electric generation are included in footnotes to Tables E-1, F-1, G-1 and H-1 of the Appendices.

*See page 49a.

Year of Operation	Amount of Material (MT/yr)	Unit Charge \$/lb U_3O_8	Undiscounted Cost of 1st Year Interval (1)	Carrying Time (Years)	Undiscounted cost of 1st Year Interval (2)	Total (2) Interval Cost
LOW CASE:						
Initial Core	442	10	9.72	1.75	10.48	10.48
2,3	185	10	4.05	1.0	4.21	7.9
4,5	154	10	3.36	1.0	3.51	6.06
6-10	154	12	4.02	1.0	4.19	17.2
11-31	154	16	5.32	1.0	5.53	54.6
Final Core	-442	16	-15.3	1.75	-16.0	-4.38
					Total	92
BASE CASE:						
Initial Core		13	12.6		13.6	13.6
2,3		14	5.7		5.94	11.16
4,5	"	14	4.74	"	4.94	8.53
6-10		27	9.14		9.53	39.0
11-31		45	15.2		15.8	156.0
Final Core		45	-43.7		-45.6	-12.5
					Total	216
HIGH CASE:						
Initial Core		18	17.4		18.8	18.77
2,3		27	11.0		11.46	21.54
4,5	"	27	9.15		9.53	16.46
6-10		54	18.28	"	19.06	78.0
11-31		100	33.8		35.32	343.2
Final Core		100	-97.01		-101.2	-27.75
					Total	450.2

SUMMARY:

Case	Total Cost $\$10^6$	Fuel Cost (mills/kWhe)	Total Fuel Cycle Cost (mills/kWhe)
Low	92	1.55	5.61
Base	216	3.64	7.7
High	450	7.61	11.67

NOTES:

1. No carrying charge
2. Includes carrying charge of 4.25%

III-A-3: Upgrading Fuels

In the future, the propo-tion of physically cleaned coal used in the electric utility industry is likely to increase from its present level of between one-half to two-thirds as low sulfur coal is used up and environmental standards become stricter. However, the average contribution of the cost of cleaning coal to the cost of electric generation by the coal-based systems is currently only about 2%; thus, even if all the coal used in electric generation were to be cleaned, the resultant impact on the cost of electric generation by coal would not be great. Advanced non-physical coal cleaning techniques such as benefaction and pyrolysis (see e.g., Ref. (26)) may see widespread use in the future. These processes remove a greater proportion of the sulfur in the coal than physical cleaning, but are also more exnensive. These approaches would be less attractive than fluidized bed and coal gasification techniques, which are discussed in section III-A-5.

When crude oil is refined, several products, including RFO, are produced. Oil refining is a mature technology and it is unlikely that technological advances in this industry will have a significant impact on the price of electric generation from RFO. RFO is actually a by-product of the refining process. That is, the other products produced at the refinery are more valuable, and hence much effort is devoted to producing more of them and less RFO than obtained after atmospheric distillation. (This is the first major step in oil refining and involves splitting crude into its "natural" constituents.) Refinery operations require a relatively large commitment of non-fuel resources, often as significant as that at the power plant itself, and use about 92% of the ancillary energy requirements of the RFO fuel cycles.

The upgrading of nuclear fuels is quite complex and typically involves a number of steps; most of these are used in the preparation of fuels for the different reactor types. Of the reactor systems considered, all but the LMFBR system require enriched uranium, and for these systems it is the enrichment step that dominates all the other upgrading steps in terms of cost and resource utilization. For an LWR, about 102 MT of separative work is required for an annual reload. Both the LWR-Pu and HTGR (which requires less U_3O_8 feed, but more separative work per pound of fuel to produce) require about 80% of the separative work requirement of the LWR system. For an LWR, the cost of upgrading fuels is roughly equivalent to the cost of harvesting fuels and resource utilizations are typically within an order of magnitude of those at the power plant itself. About 95% of the ancillary energy required for the LWR system is used for uranium enrichment. This amount of energy represents about 4.8% of the energy output of the LWR power plant. The major cost component of the upgrading of fuels for the LMFBR is the fabrication of mixed oxide (MOx) fuel elements, but as the cost of upgrading fuels for this system contributes only about 7% to the cost of electric generation, the sensitivity of generation costs to fabrication costs is not great.

The amount of U_3O_8 feed that is required for a reactor that utilizes enriched uranium is sensitive to the tails assay used at the enrichment plant. The lower the tails assay the less feed required. However, a lower tails assay requires a greater amount of separative work to obtain a specified fresh fuel assay. Consequently, for any U_3O_8 cost and separative work charge there exists a cost-minimizing tails assay. (See Ref (6) for some plots of these relationships.) In this report a tails assay of 0.25% is assumed. At the present time a move from the currently prevailing 0.20% tails assay to a tails assay of 0.275% is being contemplated (see e.g. Refs. (154) and (155)); this change seems somewhat irrational in view of current U_3O_8 price escalation. For the enriched-uranium reactors considered here, a change in tails assay from 0.25% to 0.30% requires that about 10% more U_3O_8 be mined and about 10% less separative work be performed, while a decrease in tails assay from 0.25% to 0.30% reverses these sensitivities.

The currently employed method of isotopic separation (i.e. enrichment) is gaseous diffusion (Ref. (154)). However, research is under way on both the centrifuge (Ref. (21) pg. 48) and laser (Ref (156)) methods. Both of these methods can potentially decrease enrichment power requirements by an order of magnitude or more, but it is conceivable that the increased capital expenditures that may be associated with these methods would wipe out all or part of their operating cost advantage.

A cost parameter which can potentially have a significant impact on the economics of the LMFBR system is the price of plutonium. In this report, Pu is assumed to derive its value as a replacement fuel in LWRs. This would probably be the case in an infant breeder economy. However, as pointed out by Derian and Bupp (Ref. (177)), depending on the relative capital costs of LWRs and LMFBRs, either a LWR and LWR-Pu or a LWR and LMFBR reactor economy would emerge as medium-term market equilibria, and the value of Pu would adjust so as to equilibrate the price of electric generation for the two reactors in the least-cost combination. However in the long run, if LMFBR capacity is expanded rapidly, the price of Pu could be driven to zero, depending on the rate of growth of electric generation capacity. However, in comparing reactors in the time frame selected for this study, we believe our approach to Pu valuation, tying the value of Pu to the price of U_3O_8 and separative work, is justified.

See Table III-A-4 for a summary of nuclear fuel cycle costs.

III-A-4: Transport of Fuels

The cost of electric generation by any of our study systems seems to be relatively insensitive to the cost of fuel transport. Even for the coal-based systems where the contribution of the cost of fuel transport to the cost of electric generation is the greatest, transport costs represent only about 10 - 15% of the total cost of electric generation. Any move towards increased use of western coal to satisfy eastern electric demands would, of course, increase the average cost of coal transport (or perhaps of electric transmission if this turns out to be the more economical means of energy transport over long distances). It is hard to imagine, however, that the cost of coal transport would more than double on a national average basis, especially in view of some of the newer methods for coal transport (i.e., unit trains and coal slurry pipelines). Further, even if the average cost of coal transport doubled from its current level of $4.50/ton to $9.00/ton, the cost of electric generation for the coal-based systems would increase by only 10 - 12%.

Oil transport is even cheaper than coal transport; since the current total cost of oil to electric utilities is more than double the current cost of coal and this relationship is not likely to change in the near future (see Section 2 above), the cost of electric generation by RFO is even less sensitive to fuel transport cost than for the coal-based systems.

Finally, since transport of nuclear fuels represents less than 10% of the nuclear-fuel cost to electric utilities, and since the cost of these fuels represent at most 30% of the cost of electric generation by the nuclear system, the sensitivity of generation costs to the cost of fuel transport is negligible for nuclear power generation.

III-A-5: Conversion to Electricity

The costs and resource utilizations associated with the conversion to electricity step represent quantities attributable to power plant construction and operation and are significant for all of the systems studied. In fact, for the nuclear plants the non-fuel costs of electric generation (which occur primarily at the power plant) range from about 67% of total generation costs for the LWR system to over 90% for the LMFBR system. Similarly, except for land use, resource utilizations for the nuclear power generation systems are dominated by those occuring at the power plant.

For the coal-based systems, about half of the costs of electric generation are non-fuel expenditures and, in contrast to the nuclear systems, non-fuel resource utilization necessary for the harvesting of fuels and transport of fuels are comparable with those required at the power plant.

Due to the high relative cost of crude oil, the contribution of non-fuel costs to electric generation cost is least for the RFO system, at only about 20%. Further, resource requirements for the harvesting (extraction), upgrading (refining) and transport of these fuels are comparable with those required at the power plant itself.

In view of the above discussion it is not surprising to find that the costs and resource utilizations for nuclear power plants are, in general, greater than those for coal-based power plants, which are more than those for oil-fired power plants. In fact, even the most expensive coal-based plant (the coal-gas/combined-cycle plant) costs about 5% less than the cheapest nuclear plant (the LWR) to build, while the cheapest coal-based system (the fluidized-bed system) costs about 45% less than the most expensive nuclear system (the LMFBR) to build.

The fluidized-bed system seems to involve about 25% less capital expense than the other two coal-based systems, while among the nuclear systems, the LMFBR is projected to cost about 30% more than either an LWR or HTGR to build.

As far as total electric generation costs are concerned, the high price of coal and RFO yield electric generation costs for these systems that are significantly higher than for the nuclear systems. In fact, even for the coal-based system with the lowest projected generation cost (the fluidized-bed system at 27.1 mills/KwHe), the electric generation cost exceeds that for the most expensive nuclear system (the LWR at 22.7 mills/KwHe), by about 20%. Further, the current price of RFO makes the electric generation cost (42.5 mills/KwHe), almost double that for the LWR for the base case.

In the time frame specified for this study the fluidized-bed system seems to be the cheapest coal-based electric generation scheme, while the HTGR seems to be (marginally) the cheapest nuclear generation scheme. (These conlusions are, however, sensitive to the assumptions made and could likely change as we move into the next century, e.g. high efficiency combined-cycle systems, thought to be technically feasible, could make the coal-gas/combined-cycle system the best coal-based candidate at about the turn of the century.

The coal-scrub system requires a temporarily disturbed land commitment about 50 times greater than that for a nuclear plant, but the total temporarily committed area is only about twice as big, due to the sizable exclusion areas required for the nuclear plants. Additionally, a significant permanent commitment of land is likely to be attributed to the nuclear plants due to radioactive contamination.

A large part of the water consumption for each of our study systems occurs at the power plant itself. This water is evaporated in natural draft cooling towers (our assumed power plant cooling technology). For the fossil systems a substantial amount of waste heat is discharged with the flue gas, so that less cooling water is required as a heat sink than for the nuclear systems. For those nuclear systems with greater thermal efficiencies (e.g. LMFBR and HTGR) the consumptive water use is somewhat less than for those with lower thermal efficiencies (e.g. LWR and LWR-Pu).

Since the non-fuel costs of electric generation (which are incurred primarily at the power plant) are significant for all the systems studied and many of the values we have assumed for economic parameters are likely to be quite controversial, we will now describe a number of economic sensitivity analyses.

What the future capital cost for electric power plants will be is a most controversial issue. At the same time the AEC was projecting large decreases in per killowat-electric installed cost for nuclear power plants due to economies of scale and learning effects (see e.g. References (6) and (39)), Derian and Bupp (Ref. (169)) were tabulating data which seemed to show that the cost of building nuclear power plants in constant 1973 dollars has been increasing at a rate of about \$20 - \$30/Kwe per year above the rate of increase in the price index for steam-electric power plant construction, which has itself been increasing at a greater rate than the inflation rate in the overall economy (see Ref. (39) and Ref. (232) for a critique of the AEC reactor construction cost projection). The implications of continued escalation in power plant construction costs are explored in Table III-A-2.

Recently, another factor besides increasing capital costs has led people to question the economic advantage that is usually claimed for nuclear power. The seminal detective work of Comey (see e.g. Ref. (149)-(153)) has led to the realization that nuclear power plants are today less reliable than their fossil-fueled counterparts. In Table III-A-3 we summarize the impact on future genera-

Table III-A-2: **Sensitivity Capital and Electric Generation Costs to Alternative Escalation Rates**

	System	ESCALATION RATE							
		NEGATIVE[a]		BASE=0%		5%[b]		5% + $3/kW/yr [c]	
		CAPITAL [d]	ELECTRICITY [e]	CAPITAL	ELECTRICITY	CAPITAL	ELECTRICITY	CAPITAL	ELECTRICITY
FOSSIL	Coal-Scrub	374	30.7	404	31.7	860	46.2	----	---
	Fluidized-Bed	---	----	302	27.1	650	38.1	----	---
	Coal Gas/C-C	---	----	409	30.9	880	45.9	----	---
	RFO	---	----	280	43.2	596	53.2	----	---
NUCLEAR	LWR	370	21.0	424	22.7	901	37.8	1269	49.5
	LWR-Pu	370	19.6	424	21.3	901	36.4	1269	48.1
	LMFBR	420	17.6	550	21.7	1169	41.4	1537	53.0
	HTGR	370	18.5	440	20.7	935	36.4	1303	48.1

a. From Ref. (6).

b. Long term escalation rate in the energy sector projected in Ref. (8).

c. Adds historical excess of capital cost escalation for nuclear plants above that for all electric electric power plant construction to the 5% energy sector escalation rate projection. (169)

d. Capital cost in $/kW.

e. Electricity cost in mills/kWhr.

Table III-A-3: <u>Sensitivity of Electric Generation Costs to Capacity Factor</u>

The capacity factor is defined (as in Ref. (149)) as the actual output of the power plant per year divided by the output that would obtain if the plant were to produce electricity at its maximum rated capacity throughout the year. Numbers given in the body of the table are electric generation costs in levelized mid-1974 mills/KwHe.

	System	Capacity Factor		
		Base	Historical[a]	
		75%	Fossil = 62%	Nuclear = 55%
FOSSIL	Coal-Scrub	31.7	35.2	--
	Fluidized-Bed	27.1	29.6	--
	Coal-Gas/C-C.	30.9	34.2	--
	RFO	43.2	45.4	--
NUCLEAR	LWR	22.7	--	28.2
	LWR-Pu	21.3	--	26.8
	LMFBR	21.7	--	28.6
	HTGR	20.7	--	26.2

a. From Ref. (149).

tion costs of the continuation of historical annual load factors (actually Comey calls these "plant capacity factors" which refer to the actual output of the plant for the year as a percentage of the output that would be produced if the system were to produce at its maximum design capacity throughout the year).

A third set of parameters which could well effect relative power plant economies in the future are the power plant thermal efficiencies. The only system studied which has the potential for significant increase in thermal efficiency is the coal-gas/combined-cycle system. If advanced gasifiers such as two-stage entrained flow gasifiers (see e.g. Ref. (105)) can be developed, and improved turbine-blade cooling methods are developed (see e.g. Ref. (101)), a coal-gas/combined-cycle thermal efficiency of perhaps 53% could be achieved (as compared with the base case assumption of 37%. The implications of this change would be a coal-gas/combined-cycle electric generation cost of about 26.3 mills/KwHe as opposed to the base case figure at 30.9 mills/KwHe. Many have argued (e.g. several papers in Ref. (105)) that advanced gasifiers will cost less than Lurgi-type gasifiers. Thus in view of expected increases in the price of coal, the increased efficiency (and lower capital cost) potentially achievable with a coal-gas/combined-cycle make it a strong contender for the cheapest method of electric generation from coal around the turn of the century.

One final point merits discussion here. Although not much of an attempt has been made to estimate the costs of dismantling nuclear reactors at the end of their useful service life (see e.g. Ref. (167) for one attempt at this) we have heard estimates of dismantling costs as high as the cost of construction. When this is collapsed to present value and levelized to average cost, the following increases in generation costs result: about 3.7 mills/kWhe for an LWR, about 3.9 mills/kWhe for an HTGR and about 4.9 mills/kWhe for an LMFBR. The decision to dismantle the plant and restore the land to other uses has not been made at this time. Refer to Table III-A-4 for a comparison of this cost to other nuclear fuel cycle costs. See also Table III-A-5 (note e).

Table III-A-4: LWR Fuel Cycle Cost: Base Case

Year of Operation	Amount of Material (MT/yr)	Unit Charge	Undiscounted Cost of 1st Year Interval (1)	Carrying Time (Years)	Undiscounted cost of 1st Year Interval (2)	Total Interval Cost
FUEL COST:		$/lb U_3O_8				
Initial Core	442	13	[illegible].6	1.75	10.48	10.48
2,3	185	14	5.7	1.0	4.21	7.9
4,5	154	14	4.74	1.0	3.51	6.06
6-10	154	27	9.[illegible]4	1.0	4.19	17.2
11-31	154	45	15.2	1.0	5.53	54.6
Final Core	-442	45	-43.7	1.75	-16.0	-4.38
					Total	216
UF_6 CONVERSION:		$/kg U				
Initial Core	554	3.30	1.24	1.75	1.33	1.33
2,3	232	3.30	0.52	1.0	0.54	1.02
4-31	193	3.30	0.43	1.75	0.45	6.7
Final Core	-554	3.30	-1.24	1.75	-1.33	-0.37
					Total	8.66
ENRICHMENT:		$/SWU (3)				
Intial Core	203	75	15.2	1.5	16.2	16.2
2-31	102	75	7.65	0.75	7.82	133.0
Final Core	-203	75	-15.2	1.5	-16.2	-4.57
					Total	144.6
FABRICATION:		$/kg U				
Initial Core	87	70	6.09	1.25	6.42	6.42
2-31	27.5	70	1.93	0.5	1.97	33.0
Final Core	-87	70	-6.09	1.25	-6.42	-1.8
					Total	37.59
REPROCESSING WASTE MGT:		$/kg U				
Initial Core	0	--	--	--	--	--
2-29	26	120	3.12	0.5	3.06	50.0
Final Core	0	--	--	--	--	--
					Total	50.0

SUMMARY:

	Total Cost ($$10^6$)	Fuel Cost (mills/kWh)	
Fuel	216.0	3.64	
UF_6	8.66	0.14	
Enrichment	144.6	2.44	
Fabrication	37.59	0.64	
Waste	50.0	0.84	
		7.7	Total
(Dismantling)		(3.7)	(Not normally included)
		(11.4)	

NOTES:
1. No carrying charge
2. Includes carrying charge of 4.25%
3. SWU-superative work unit

III-A-6: Management of Final Wastes

For the fossil systems, management of final wastes consists of the disposal of bottom ash, recovered fly ash and sludge from the sulfur recovery system. The handling of ash is relatively simple, so that the costs of management of final wastes (which are not separated from conventional plant O & M costs in our Appendix data tables) are small for the RFO and coal-gas/combined-cycle systems where no sludge is produced. For the base case we have chosen ponding (see e.g. Ref. (90)) for sludge disposal with a projected cost of $2.50/ton; this translates to a sludge disposal cost of about 0.5 mills/kWhe for the coal-scrub system and about 0.33 mills/kWhe for the fluidized-bed system (which is regenerative) and this is included in power plant O & M costs. The only significant non-fuel resource requirement for management of final wastes for the fossil systems is, or course, land use. The requirement for ash disposal is about $27m^2$/MWe-yr based on pond disposal for the three coal-based systems and about one-tenth of this amount for the RFO system. For the coal-scrub system, sludge disposal requires about 3 times as much land as ash disposal, whereas for the fluidized-bed system only about half of this incremental land use is required. If the upper bound on projected sludge disposal costs by ponding given in Ref. (90) of $4.50/ton obtain, electric generation costs for the coal-scrub system would go up by about 0.4 mills/KwHe, and for the fluidized-bed system about 0.2 mills/KwHe. If chemical fixation of sludge is the alternative selected, sludge disposal costs of from 0.4 to 1.8 mills/KwHe for the coal-scrub system and from 0.3 to 1.2 mills/KwHe for the fluidized-bed system are possible.

For the nuclear systems, management of final wastes consists of reprocessing and shipment of spent fuels as well as management of the non-useable products of this reprocessing. The cost of these activities is generally about 0.8 mills/KwHe, which for all of our reactor concepts represents less than 5% of the electric generation cost. Ref. (6), Table II-2-15 projects about a halving of all reprocessing costs by 2020, except those for the LMFBR (where only a 20% reduction is projected). This would lead to about a 0.4 mills/kWhe reduction in electric generation costs. For the base case a $10/Kg cost of high level waste management was assumed based on the weight of the spent fuel (not the final waste itself). The fission products are less than 3% by weight of the spent fuel. Thus, the disposal costs per unit of fission products (e.g., high level wastes) are over 30 times the costs indicated. This is representative of the geological concepts given in Ref. (20). Should the highest cost alternative (solar escape) given in Ref. (20) be chosen, the change would be about $90/Kg and electric generation costs would rise by about 0.5-0.6 mills/kWhe. Social costs of possible future releases of stored wastes from coal or nuclear plants have not been calculated. See Table III-A-4 for a summary of nuclear fuel cycle costs.

III-A-7: Multiple Sensitivities

In the previous sections of this chapter we have explored the sensitivity of the cost of electric generation to changes in several base-case parameters whose values could most plausibly change in the future. Thus far, resultant electric generation costs have been tabulated for variations in one parameter at a time. As simultaneous variations in several base-case parameters are equally plausible, the major purpose of the present section becomes that of tabulating electric generation costs for several of the most interesting multiple parameter variation cases. Additionally, although a detailed analysis of regional cost differences are beyond the scope of this work, we argue briefly that such differences can indeed be a significant factor in terms of the economic competitiveness of the alternative study systems.

In Table III-A-5 we have simply tabulated the impact of varying some of the base case parameters discussed in Section III-A-6 simultaneously. Note that these results indicate that no one system dominates any other on a cost basis for all plausible parameter value assumptions. When high fuel and high capital costs are considered which represent 3% and 5% escalation to 1990, along with historical load factor, electricity costs from coal double while nuclear costs triple. This reverses the energy cost advantage of nuclear po. .. and illustrates the future uncertainty of comparative energy costs of nuclear versus coal plants.

Regional coal prices last December varied from 16¢/MBtu to $1.08/MBtu in mid-1974 dollars according to Ref. (31). Using base-case assumptions for other economic parameters, this gives a range of generation costs for the coal-scrub system of from about 19.5 to 36.0 mills/KwHe, for the fluidized-bed system of from 14.9 to 31.4 mills/KwHe and for the coal-gas/combined cycle system of from .8.7 to 36.0 mills/KwHe. The high current price of oil has dampened out the effect of regional differences in RFO prices to the point where they are not significant. Nuclear fuel costs have not shown, and probably will continue not to show, significant regional differences.

It is a significant accomplishment of the AEC's (now ERDA's) capital-cost estimating computer program CONCEPT (see e.g. Ref. (27)) that regional capital cost differences may be updated almost continuously. Using this program Ref. (21) and our definition for capital costs, regional capital costs for the coal-scrub system range from \$354/Kwe to \$425/Kwe, which corresponds to electric generation costs of from 30.1 mills/KwHe to 32.4 mills/KwHe. In the same reference regional capital costs for LWRs range from \$382/Kwe to \$460/Kwe, which corresponds to a range of LWR electric generation costs of from 21.4 mills/KwHe to 23.8 mills/KwHe.

Table III-A-5: Sensitivity of Electric Generation Costs to Multiple Parameter Variations

	COSTS (mills/kWh)								
System	Low Low Base	Low Low Hist	Base Base Base	Base Low Hist	High Base Hist	Base High Hist	High High Base	High High Hist	Fuel[a] Capital[b] Capacity Factor[c]
Coal-Scrub	26.6	30.1	31.7	35.2	44.2	52.7	55.2	61.6	
Fluidized-Bed	21.9	24.4	27.1	29.6	38.6	42.9	47.1	51.9	
Coal-Gas/C-C	25.8[d]	29.1	30.9[e]	34.2	43.2	52.4	54.9[f]	61.4	
RFO	31.8	34.0	43.2	45.4	45.4	57.4	53.2	57.4	
LWR	18.9	23.7	22.7	25.8	30.3	32.[illegible]	53.5	68.7	
LWR-Pu	18.2	23.0	21.3	24.4	28.7	29.1	51.4	66.6	
LMFBR [g]	17.7	23.2	21.7	23.1	27.9	28.0	52.4	70.8	
HTGR	17.5	22.4	20.7	23.4	27.4	28.5	50.4	66.1	

a. The high, low and base fuel costs correspond to those given in Table III-A-1 with the base RFO cost doubling as the high RFO cost.

b. The high and low capital costs correspond to the right-most and left-most estimates provided in Table III-A-2.

c. The historial (Hist) capacity factors assumed are those given in Table III-A-3.

d. Based on the improved coal-gas/combined-cycle efficiency discussed in Section III-A-6, the cost here would be 22.7 mills/kWhe

e. Note d, but 26.6 mills/kWhe

f. Note d, but 38.5 mills/kWhe

g. If dismantling costs of the power plant were 100% of original costs, the following equivalent mills/kwh charges could be:

	Low	Base	High	Capital Costs (mills/kWh)
LWR, LWR-Pu	3.2	3.7	11.1	
LMFBR	3.7	4.9	13.7	
HTGR	3.3	3.9	11.5	

III-A-8: Research and Development Costs

Projected R & D costs were collected for each of the electric generation systems selected for study and are summarized in Tables III-A-6 and III-A-7. In the past, many agencies have been responsible for energy R & D programs (see, e.g., References (219), (220), etc.). However, pursuant to its founding early this year, most of the administration of energy R & D programs and virtually all co-ordination of such programs have been made the responsibility of the new Energy Research and Development Administration (ERDA). Consequently, virtually all existent long-range projections of R & D expenditure scenarios were formulated in the pre-ERDA era. In this study we have, in particular, relied heavily on an assessment of energy R & D programs and recommendations made in a recent FPC report (Ref. (218)), as it takes into account most previous energy R & D recommendations and it focuses specifically on the electric-power industry. We can add to this the proposed FY '76 ERDA funding levels to gain some insight into likely R & D costs required for emerging energy technologies. (See e.g., References (223) and (224). For an illuminating discussion of issues involved in setting energy R & D priorities, see Ref. (225).) However, the genesis of ERDA has, in the words of several ERDA officials we have spoken to, [illegible]nt the beginning of a "whole new ballgame" in energy R & D. The new game pl[illegible] (i.e. ERDA's proposed funding levels for energy R & D for 5 - 10 years into the future) is due to be delivered to Congress at the end of June, 1975 (see, e.g. Ref. (226)). Further, as the emergence of the "energy crisis", has kindled a large amount of congressional interest in and concern over energy R & D (e.g. Ref. (178)), exactly what this proposed plan will entail is, at the moment, not at all easy to surmise.

With this caveat in mind, we return to Table III-A-6, which shows projected (pre-ERDA) R & D expenditures and expected commercia[illegible]ation dates for electric

Table III-A-6: Projected R & D Costs for Alternative Electric Power Generations Systems

Cost figures given are in mid-1974 dollars. The completion date refers to the commercialization date for developing technologies and to the end of the R & D programs for technologies that are now commercial.

SYSTEM	Projected R&D Cost (Millions of dollars)	Projected Completion DATE of Program
Coal-Scrub[a]	91	1981
Fluidized-Bed[a]	395	1981
COAL-GAS/ C-C[a]	882	1984
RFO[a]	0[c]	----
LWR[a]	311[d]	1984
LWR-Pu[a]	311[d]	1984
LMFBR[b]	6500	1987
HTGR[a]	421[d]	1984

a. From Ref. (218); for corroboration and some discrepancies see *e.g.* Refs. (215), (216), and (219).

b. From Ref. (6). This figure refers only to the LMFBR program. Were we to combine with this the expenditures on other breeder concepts and breeder "support technologies" as is often done in breeder cost/benefit analyses, the figure would rise to 9.5 billion mid-1974 dollars. (See Refs. (6), (176), (178), and (232) for more on the proposed Breeder budget.)

c. Much of the coal-scrubber research will apply to oil systems.

d. The HTGR and LWR categories include a 50-50 split of the approximate $600 million LWR and HTGR safety category. This amount is included in both the LWR and LWR-Pu totals.

Table III-A-7: Support R & D Programs for Alternative Electric Power Generation Systems

Cost figures given are in mid-1974 dollars and refer to R & D expenditures projected to be necessary from 1975-1984.

Program	Projected R & D Cost[a] (Millions of Dollars)
COAL:	
Mining Improvement	278
Mining Health and Safety	366
Fuel Cycle Environmental Controls	336
Power Plant Environmental Controls	651
OIL:	
Stimulation of Oil Reserves	232
Exploration	103
Fuel Cycle Environmental Controls	311
Power Plant Environmental Controls	213
NUCLEAR:	
Uranium Exploration and Mining	49
Uranium Enrichment	397
Fuel Cycle Environmental Controls	479
Reactor Environmental Controls	2113
Radioactive Waste Disposal	171
Other Breeders	1400[b]
Breeder Support Technology	1600[b]

a. Unless otherwise noted, from Ref. (218), see also References (215), (216) and (219).

b. From Ref. (6).

generation system included for analysis in this study. This Table includes those programs which can be directly related to a particular electric-generation system (and, therefore, primarily those programs directly related to a particular type of power plant). One notes immediately in this table the predominance of the LMFBR program. Finally, in Table III-A-7, we include estimates of R & D funds for some programs that will contribute to the commercialization or acceptance of at least one of the study systems, and to other parts of the energy economy as well, and where, therefore, the allocation of funds among to separate systems is not possible. In this table, the large allocation of funds to (primarily) breeder reactor support programs is apparent, as well as the significant allocation of funds to environmental control research, especially those thought to be necessary to secure widespread commercial acceptance of nuclear reactors.

III-B: Environmental and Health Impacts

III-B-1: Harvesting Fuels

In the detailed tables in Appendices A-H we have entered data for both the impacts of underground and surface mined coal. For uranium we have not disaggregated the two types of mining but have taken the impacts directly from reports which assume a certain fraction of the mining to be of each type. At present about 50% of coal and uranium is surface mined and the trend is toward more surface mining. (8,25,137). In the long term, however, this trend must be reversed as progressively deeper deposits are utilized. In addition, there is a change occurring in the geographic distribution of coal mining. This shift is toward a larger proportion of western surface-mined coal, in contrast to the present situation in which only about 10% (by weight) is mined in the Rocky Mountain and Pacific States. In addition, there seems to be an inverse relationship between sulfur content and the surface slope angle of eastern strippable deposits. Thus the contemplated restriction on mining above a certain angle in combination with continued sulfur restrictions will lead to increased use of western coals. (53,135). We have chosen eastern underground mined coal and western surface-mined coal as typical of the two types of mining and the two regions. For uranium mining we have used a "national average" mine and mill to illustrate the impacts. (9).

Coal mining has traditionally been considered one of the most hazardous and ill-paid of occupations. However, since the passage of the Federal Coal Mine Act of 1969 and the Occupational Safety and Health Act of 1970 conditions have been steadily improving. Dust levels, exposures to which is directly related to the prevalence of coal workers pneumoconiosis (CWP), and accident rates are falling. In addition, the miners' wages and other benefits* are beginning to rise

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* For example, in 1972 the Black Lung Benefits Act relaxed the criteria for awarding compensation to miners.

in relation to other industries. However, there still is a serious question of social equity related to coal mining. The entire society is receiving the benefit of coal mining while a small but significant minority is undergoing much of the damage. (24,25,59,133-139)

The occupational risk of accidental death or injury per million miner-hours is very similar for coal and uranium mining. However, many fewer miner-hours are needed in the uranium cycle for a comparable energy output (4, 5, 7). Thus, the individual miners undergo similar risks but the overall social impact is approximately 20 times greater in coal mining.

At the present time, coal miners have about 150 times greater risk of developing lung disease from their occupation than do uranium miners. The impact of this difference is actually smaller than this factor, because, in general, CWP is less damaging and more amenable to treatment than lung cancer.

If the dust levels are maintained rigorously at the present standard (2 mg/m^3), the rate of CWP/MWe-yr should begin to drop as the total average dose to the miners is reduced. Table III-B-1 specifies what this rate would be under several different assumptions (5,25,137). Miner output/day has reduced from 14.2 MT (1969) to 10.2 (1973) mainly due to new mining legislation to improve miner working conditions. The CWP/MWe-yr increased because of the longer time and exposure to produce a ton of coal. The exponential notation is used extensively in the appendix, but is also used for the first time in Table III-B-1. Please note nomenclature in the table.

Table III-B-1: <u>Possible Future Black Lung Disease</u>

(Simple CWP/MWe-yr; Assumes 220 miner-days/year at 2.0 mg/m^3 dust level; Exponential notation: 8.2 - 4 = 8.2×10^{-4} = 0.00082)

	Power Plant Efficiency		
MT/Miner-day Output ⓐ	37%	41%	45%
10.2 (1973)	8.2 - 4	7.4 - 4	6.7 - 4
14.2 (1969)	5.9 - 4	5.3 - 4	4.9 - 4

ⓐ MT - metric ton at 11600 BTU/lb

These rates are 50-100 times lower than the present total CWP estimate and correspond to an individual risk within a factor of 2 higher than the median lung cancer risk for the underground uranium miner.* It should be pointed out that simple-CWP is a much less serious disease than lung cancer and that there is unlikely to be a risk of the more severe forms of CWP at this dust level. In addition, however, other types of lung disease are associated with both coal and uranium mining.

The milling of uranium also creates an acid waste along with BOD, suspended solids, total dissolved solids, etc., which are disposed of along with the solid mill tailings in a waste pond. The levels of Th and Ra probably preclude the use of the tailings as construction fill or in similar applications near human habitation (3,157, 158). Over a very long period of time, there may be a significant human radiation dose from the Radon gas released from these tailings of left uncovered, but a 20 ft. layer of dirt would reduce the Radon emission by a factor of 10 (Ref. 157). The uranium tailing could produce 0.5 deaths/MWe-yr over 80,000 years if not sealed (Ref 233). This is potentially an enormous effect, but acts over a very long time period compared to the plant lifetime. This effect is excluded in calculating health effects.

Various types of oil spills produce the most damaging of the environmental impacts from oil production. Both the import of foreign oil and the production of off-shore or outer continental shelf oil have the potential for accidently releasing very large amounts of oil into the ocean. Several recent studies (115-118) have looked into this problem in some depth and have tried to determine the kinds of probabilities, quantities, effects and control techniques that are appropriate for various types of spills. Large storms, hurricanes, earthquakes, and ship collisions are the kinds of initiating events which could trigger such a release. In addition, the "routine" spill from tankers, oil platforms and pipelines may be important in some areas.

Although there is apparently little or no human health risk from the

* Risk per miner-year	Present	Future
Uranium: Cancer rate	$3\ (10)^{-4}$	?
Coal: CWP rate	$4.5\ (10)^{-2}$	$4.9\ (10)^{-4}$

toxicity of oil spills (114) there can be considerable impact on the ecology, economy and recreational potential of an area. In addition, there is a safety risk because of the potential for large-scale fire if, for example, an oil tanker should break apart and burn near a populated area.

In both uranium and coal extraction, surface mining is distinctly safer both in terms of accidents and lung disease.* Surface mining disrupts approximately 3 times more land by stripping than underground mining does by subsidence. Coal mining by the longwall method causes more subsidence but the amount and location of the subsidence is more predictable than in room-and-pillar method. The acid waste produced by underground coal mining in the east has no counterpart in western surface mining because there is little or no pyrite sulfur in the western coal to form sulfuric acid. There may be some problems with akaline and other discharges, however. Reclamation of surface mined land is a difficult and sometimes lengthy procedure in areas with low rainfall and shallow topsoil as, for example, in the western range states. It seems likely, however, that some type of legislation will be enacted soon to enforce reclamation of land disturbed by surface mining. (58-62)

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* There is some evidence that dust levels at certain surface coal mines may be high enough to produce CWP. (25). Surface coal miners have about 50% of the accident rate of deep miners per million miner-hours. And, in addition, the output per man hour is about 3 times higher (137).

III-B-2

Upgrading Fuels

The fossil systems have much less complicated fuel-upgrading steps than the nuclear systems. In fact, western coal is not prepared at all prior to transport to the power plant. Eastern underground coal is physically cleaned in order to lower the sulfur content by removal of part of the inorganic pyrite. Also, this process removes some ash and consequently raises the Btu content per pound slightly. Forty to fifty percent of the sulfur in most coals can be removed by this cleaning. (63, 64)

There is a wide range in the mixture of petroleum produced at oil refineries. The amount of residual fuel oil (RFO), the fuel in our reference oil system, can vary from 5 to 90% of refinery output, depending on the type of crude oil, the kind of refining process utilized, and the requirements of the company. Consequently, the allocation of impacts at the refinery to a unit of RFO is not a simple process. We have used the impacts tabulated by several studies that have tried to calculate the proportion of impacts to be ascribed to RFO using average refinery output percentages. (1, 5, 7, 119)

Upgrading of nuclear fuel consists of several quite different steps. Enrichment in the LWR, LWR-Pu and HTGR cycles requires relatively large amounts of electricity. The emissions of the coal fired plants which operate the enrichment plants are often assigned to the nuclear fuel cycle. This is usually justified by the fact that the enrichment plants actually, at present, have their own captive power plants. However, this calculational procedure is not entirely consistent, in that there is electricity required for most if not all steps in all the fuel cycles, and no assignment is made of the emissions which result from the production of that electricity. Furthermore, in the future, enrichment plants may not operate with captive plants or may operate with non-coal plants. Just as in energy accounting, there is no obvious end to this secondary-impact accounting. Should one, for example, count the emissions which occur in the manufacture of the steel used in the power plant? We have not attempted to do this kind of accounting and would urge that the conceptual questions be resolved before it is undertaken. (9)

The LMFBR system requires no enrichment capacity.

The fuel fabrication facilities for each of the four nuclear systems are significantly different from one another. LWR fabrication requires the processing of relatively non-toxic uranium. The loss of approximately 0.8% of the throughput is of little concern and leads to little or no health and environmental impacts. LWR-Pu plants use uranium and plutonium (mixed oxide, abbreviated MOx) fuels, and consequently the potential hazard is much greater. (3) This hazard exists for both the workers in the plants and the public outside. The tables in appendix F and G indicate a much higher level of containment than the 99.2% common in uranium fabrication plants. The costs of fabrication are also expected to be much greater because the level of care, accounting, protection, maintainance and containment must be orders of magnitude more rigorous. Table III-B-2 indicates the releases of plutonium under various assumptions and illustrates that this problem is potentially serious.

Table III-B-2: Dilution Volumes Required for Fabrication Plant Releases

The dilution volumes in air are listed in units of million cubic meters. The loss is listed in Ci/Mwe-yr. The dilution volumes were calculated by dividing the loss in Ci by the MPCa* standards for natural uranium and plutonium-239. The dilution volumes have been corrected to account for the mix of isotopes in reactor grade plutonium.

Loss Fraction	LWR		LWR-Pu		LMFBR	
	Loss Ci/MWe-yr	Dilution Volume $10^6 m^3$	Loss	Dilution Volume	Loss	Dilution Volume
8.0 - 3	9.1 - 5	3.0 + 1	1.2	2.0 + 7	5.2	5.7 + 7
8.0 - 5	9.1 - 7	3.0 - 1	1.2 - 2	2.0 + 5	5.2 - 2	5.7 + 5
8.0 - 7	9.1 - 9	3.0 - 3	1.2 - 4	2.0 + 3	5.2 - 4	5.7 + 3

The LMFBR fabrication plants also use MOx and exacerbate the problem even further as indicated in Table III-B-2. There is about 4 times as much plutonium processed in a LMFBR fabrication facility because a fast breeder is fueled solely with plutonium.

HTGR's have very complicated fabrication processes and facilities. Several different types of fuel particles are fabricated. There is no plutonium in these fuels although the hazards of direct radiation are high because of U-233 in the fuel. The U-233 will be contaminated with U-232 which decays into several very dangerous daughter products. Remote or semi-remote handling will be required for the fabrication of U-233 fuel particles. (180, 183, 184)

* Maximum Permisible Concentration in air. (189) See Section III-B-6.

III-B-3:
Transportation

Transportation accidents are a significant part of the public health impacts from coal plants. An increased use of coal slurry pipelines (53,62), unit trains and mine-mouth power plants will reduce this impact by reducing the average distance coal is transported and decreasing the accident rate per ton-mile. The impacts of RFO transport are similar to those that result from crude transport; these are discussed in section III-B-1.

The transport of nuclear fuels has very small accidental death and injury impact because of the small amount of material actually transported. The routine emissions and radiation dosages are also small compared to those from other parts of the nuclear fuel cycles. There is concern however, about the possibility of accidental releases of radionuclides, especially from accidents involving the transport of irradiated fuel and high-level waste. Estimates have been made of the maximum possible releases in such accidents and the associated probabilities (9,14,18,19). The expected values are low but there are low probability/high consequence events which have been identified. (See section III-B-7 for a discussion of the implications of different risk distributions.) There are stringent regulations involving the transport of highly radioactive materials, and strict adherence to these regulations should keep the level of emissions from accidents and routine operations to a minimum, compared to other parts of the nuclear fuel cycles. It should be pointed out, however, that there have been no significant shipments of high level waste, to date. In fact, the final design of high level waste shipment casks has not been selected. It is impossible to assess the total impacts of a fuel cycle which is not yet complete and for which no final designs and plans are available.

The potential for diversion of fissile material by unauthorized groups is a further concern during the transport of nuclear fuels. This problem is discussed in the context of the entire nuclear fuel cycle in section III-B-7.

III-B-4:
Conversion

The conversion of fossil fuels into electricity produces the largest amount of emissions in these fuel sycles. SOx, NOx and particulates are the pollutants which have been identified as being most critical, although toxic metals may be very important for some types of coal and oil combustion. (5,81-82)

There has been a great deal of debate recently about the SOx emission standards for fossil plants. Not only is there uncertainty about the relationship between emissions and ambient levels but there is the great uncertainty about the dose-response relationships. Furthermore, the relationships are clouded by the great uncertainty about exactly which pollutants are causing the observed effects. SOx, for example, may exert its effect through some or all of the various sulfates which are formed from it. NOx also interacts in the environment and seems to exert an impact through intermediary substances. Thus all the pollutants have to be considered in relation to the environmental conditions such as temperature, humidity, sunlight and the presence of other chemicals.

The technical reliability as well as the need of SOx control has been heatedly contested in recent years. It seems, however, that the lime (and possibly limestone) scrubbers can operate reliably and with removal efficiencies of up to about 90% on conventional coal and oil boilers with a thermal efficiency penalty as well as increased capital and operating costs. (15) Low-Btu gasification/combined-cycle combustion seems to offer potential sulfur removals of 99% or more in the combination with thermal efficiencies of 45%. There have been some claims that the thermal efficiencies of gasification and combustion might total as much as 50% or more. (5,28) In this case the limiting factor may not be emission regulations but the need to provide a very clean gas for turbine combustion to avoid turbine blade damage. (30) Fluidized-bed combustion seems to have the potential to remove up to 95% of the sulfur contained in the fuels. (13)

The present SOx emission standards will not only have to be maintained but strengthened in the future if total SOx emissions burdens are not to rise considerably. (2) Table III-B-3 indicates the removal efficiencies which would be needed for different kinds of fuels and more stringent emission regulations. If the standard were ten times more stringent than at present, both residual fuel oil and western coal could be burned with 95% removal of sulfur. However, if the standard were to be 100 times more stringent, SOx removal would have to be greater than 99% for all the fuels and only low-Btu gasification/combined-cycle combustion might be able to meet the requirement.

Table III-B-4 illustrates the level of premature deaths that would be associated with emissions of SOx at the rates allowed both by present standards and by more stringent standards in the future. The reader is warned that these numbers, which are extrapolated on a linear basis from reference (15), are subject to a wide band of uncertainty. The upper and lower estimates in each box of the table refer to the range between remote and urban power plant sites in reference (15).

In order to provide a very rough comparison with the risk from nuclear power accidents the results of the following calculations are presented.

- 100 1000-Mwe power plants operating at 75% capacity for 30 years
- Emission rate of 0.06 lb. SOx/million Btu (5% of present standard(100))
- 41% average thermal efficiency

Uncertainty factor of 1/10 to 2 times in the dose-response relationship suggested by reference (15), gives 72 - 4320 premature deaths in 30 years.

This calculation is very approximate and leaves out many additional impacts such as nonfatal respiratory diseases, materials damage and effects of other pollutants such as NO_4, CO, solid particulate, etc.

Table III-B-3: Sulfur Removal Efficiency Required to Meet Standards

	Sulfur Standards (lb SO_2/ million BTU input)		
Fuel	Present STD 1.2 - coal 0.8 - oil	10% Present STD 0.12 - coal 0.08 - oil	1% Present STD 0.012 - coal 0.008 - oil
Eastern Coal 3.3% S 2/3 of which has been cleaned to remove 40% of the sulfur. 12,000 Btu/lb	70.2%	97.0%	99.7%
Western Coal 0.8% S 9000 Btu/lb	32.5%	93.3%	99.3%
Residual Fuel Oil 1.0% S $6.3(10)^6$ Btu/bbl	0	88.5%	98.9%

Table III-B-4: Health Effects of SOx:

Premature deaths/Mwe-yr
The low number in each box represents a remotely sited plant , the high number an urban plant as defined by ref.(15)

	Sulfur Standards (lb SO_2 / million BTU input)		
Thermal Efficiency	Present STD 1.2	10% STD 0.12	1% STD 0.012
37%	7.1-21.1 $^{-3}$	7.1-21.1 $^{-4}$	7.1-21.1 $^{-5}$
41%	6.4-19.1 $^{-3}$	6.4-19.1 $^{-4}$	6.4-19.1 $^{-5}$
45%	5.8-17.4 $^{-3}$	5.8-17.4 $^{-4}$	5.8-17.4 $^{-5}$

Present emission standards for NOx are 0.7 lb/million Btu for solid fuels and 0.3 lb/million Btu for liquid fuels, which roughly corresponds to the best available emission rates for new boilers. By combustion modification in boilers these rates can be lowered by a factor of 1.5 or 2. Fluidized-bed combustion should be able to meet or exceed the 0.14 lb/million Btu regulation projected for 1985. (13,15,91-98)

Although the removal of particulates by weight is very efficient, the smaller particles which are not removed may have a significant health impact. (129)

Nuclear power plants release relatively small amounts of toxic material during normal operations compared to fossil plants. The concern and uncertainty lies with the possible release of very large amounts of radioactive material as the result of accidents. Since the beginning of the nuclear power industry the probability and consequence of such accidents has been subject to considerable debate. In late 1974 the AEC issued in draft form a detailed study (WASH-1400-Draft) that attempted to identify all possible accident sequences and to estimate the probability and severity associated with each sequence. (17) This study examined LWR's without plutonium recycle and did not consider accident sequences which could result from sabotage or attempted diversion of nuclear materials. Nothing of comparable detail has been done on the other reactors or on other parts of the fuel cycles. Recognizing that the other reactors have very different characteristics and may have very different accident probabilities and severities, we shall concentrate on LWR accident risks in the following discussion.

Table III-B-5 lists the risks of death/Mwe-year for LWR's as determined by Wash-1400 (17) and also lists the range in uncertainty in both severities and probabilities as indicated by the report and by critics of the report. The total range of estimates is very large. The risks range from $3.7\ (10)^{-7}$ to 5.9×10^{-5} deat /MWe-yr based solely on W1400. We have added a factor of 20 to the high end based on the American Physical Society critique. This was due to difference in considering evacuation procedures, as well as total population dose. It should be mentioned that other estimates made in the past, if included, would extend this range appreciably in both directions.

If there was one sabotage or diversion incident in the 30 year operation of 100-1000 MWe power plants which caused 11000 somatic deaths, the risk from these causes would be 80x the risks from the high end of the range of W1400 (Rasmussen). This is 4x the high end of W1400 after the factor of 20 derived from the American Physical Society critique has been applied throughout (see Table III-B-5). Recently a very preliminary attempt has been made to utilize decision tree methodology to quantify the social costs of nuclear and fossil power systems (Ref. 234). A tentative factor of about 90 between the total social cost of nuclear sabotage and diversion compared to accidents was derived from this study. Thus, al[illegible] [illegible]uthors of this study are very insistent that their numbers are not t[illegible] [illegible]clusive, the total risk from sabotage may be very much more [illegible]t [illegible] from accidents, as well as being more difficult to determine.

Table III-B-5: Societal Dangers from LWR Accidents

Somatic death/Mwe-yr ©
W-1400 refers to probabilities and severities
in AEC draft report Wash-1400 (17).

Severity	Probability		Maximum Accident Thousand Deaths
	W-1400	W-1400 1/3x-6x ⓐ	
W-1400	3.3 -6	1.1-20.0 -6	5.0
W-1400 1/3x-3x ⓐ	1.1-10.0 -6	3.7-590.0 -7	1.7-15.0
W-1400 60x ⓑ	2.0 -4	6.6-120.0 -5	300.0

a. Ranges in Wash-1400

b. Factor of 20x applied to high end (Ref. 197)

c. Somatic effects are in same generation of people, i.e., no genetic effects.

If there was 1 act of sabotage in 100 plants over 30 yr expected operation, which killed 11000, the risk of sabotage would be 4x larger than the high end of the range shown (1.2×10^{-3})

The table also lists the maximum size accident that would be associated with each set of assumptions about severity.

In order to very roughly compare these risks to those of a fossil system the results of the following calculation are presented:

100 1000-Mwe power plants operating at 75% capacity for 30 years

Total deaths = acute deaths af accident plus fatalities from chronic effects (50% of latent cancer and 1% of thyroid cases assumed to be fatal)

Range of genetic effects from 0 to 100% of somatic effects is included,to but the effect of long-lived radionuclides in the environment on future generations is excluded.

Range of expected values: 1 - 5400 deaths in 30 years.

It should be remembered that this does not account for somatic and genetic illnesses, property damage and contamination expenses, which would also be the result of accidents at nuclear power plants. In addition, this expected value is the average number of deaths per 30 years which would be expected over a very long period if the actual risks are as indicated. Sabotage and long-term effects of waste storage are also excluded from this sample calculation. The number of deaths in any particular 30 year period of operation of 100 plants would most likely be quite different and could range from zero to multiples of 300,000 deaths. The reader is referred to section III-B-7 for a more detailed discussion of risk distributions.

III-B-5:

Management of Final Waste

Both coal and nuclear systems create considerable waste management and disposal problems. However, the length of time over which the waste is of concern varies considerably between coal and nuclear systems. See section III-B-7 for a brief discussion of the implications of these variations.

Coal plants with scrubbers create a large volume of messy material known as sludge. Sludge is composed of about 50% water and 50% suspended solids and various dissolved substances. The exact composition of the solids and dissolved substances depends on the technology of scrubbing and the kind of coal. There are significant concentrations of toxic elements in the sludge from most coals. The most important elements, in terms of human health, seem to be mercury and arsenic, and the sludge must be managed to minimize the release of these elements (87-90).

Depending on the technology employed, fly ash can be collected along with the sulfur and be a part of the sludge or it can be collected separately and then added to the sludge or disposed of separately.* This mixture of sludge and ash can be piped or otherwise transported to ponds which are unlined or lined to reduce permeability. It can be dewatered and/or compacted by various techniques to a level of about 70% solids so that it can be used as fill. The best and most expensive methods are various physical and chemical treatments which fix the toxic metals and make the sludge suitable for fill without worry

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* Fluidized-bed systems create a smaller amount of sludge and ash mixture with a much higher proportion of ash. In addition, elemental sulfur is produced for sale or disposal. The gasifier at a low-Btu gas/combined-cycle plant creates mostly ash and elemental sulfur. A RFO plant with scrubber would create a much smaller amount of similar mixture of sludge and ash.

about rewetting. In all these cases the aim is to reduce or eliminate the amount of dissolved solids and toxic elements that enter the hydrosphere.

In our reference coal scrubber system (wet lime) in Appendix A we have assumed that the ash and sludge are disposed of together in a lined pond. This reduces the chance of water pollution but is not optimal in terms of land use. Eventually some reclamation techniques will have to be applied to the ponds, if the land is to be reused.

Nuclear waste presents a very different set of problems. There are three types of nuclear waste described in the tables in Appendices E-H: high, intermediate and low level waste. The volume of high level waste (containing most of the fission products and most of the radiation activity in all the wastes) is very small compared to scrubber sludge, for example. However, the toxicity is very high and the material releases enough heat during its initial years of decay to require some sort of provision for heat removal.

There are two philosophies about high level waste management. One is "Storage", i.e. place the material in a location where it will be isolated from the environment and can be watched and retrieved if it starts to leak or better means of management are developed later. The second is "Disposal", i.e. put the material in some remote, stable geologic or extra-terrestrial location where, although it would be difficut or impossible to retrieve, it would remain out of the earth's biosphere for a sufficient time to allow the long-lived isotopes to decay. No permanent waste disposal or storage plan is in operation now, although many are being investigated. (19,20). Waste is now temporarily stored at Nuclear Fuel Services facilities (21) and until there is a reprocessing plant operating again, spent fuel rods are being stored at the individual power plants. (143).

The wastes classified as intermediate and low level have a very small fraction of the total original activity. However, after a few hundred years most of the fission products in the high level wastes will have decayed away, leaving the long-lived transuranium isotopes. (193) At this point the transuranium containing intermediate and low level wastes will be equally as dangerous as high level wastes. Only about 50% of the transuranium waste (in the LWR cycle) is in the high level waste. The rest of these wastes are at low level which, unlike solidified high level waste, is very heterogeneous and consists of liquids, pieces of machinery, tools, clothing, incinerated paper, etc. Disposal methods for these materials have not been investigated nearly as well as have the means of disposing of the high level wastes, although in the long-term the level of difficulty may be greater because of a similar trans-uranium content and a very much larger and more heterogeneous amount of material.

Finally, the facilities themselves can present considerable long-term waste disposal problems. Strip-mined or otherwise damaged land, tailings piles and ponds, sludge ponds and refuse banks, if not properly reclaimed, can be an aesthetic, economic, ecological and health deficits for many years. Retired nuclear facilities can be the source of continuing hazard unless properly decommissioned and dismantled or otherwise made safe. This may be quite expensive (see Section III-A-5) and be the source of additional waste for disposal or storage. (165 - 167).

No consideration is given to long-term health effects of nuclear wastes once they are deposited into retrievable storage or permanently disposed into geological formations, ejected into the sun, etc. Since no long-term waste management plan has been chosen at this time, it is impossible to properly evaluate the potential health impacts.

III-B-6:
Indices

In comparing one system to another it is usually necessary to make judgements about the relative weights to be given to completely different kinds of impacts and emissions. This is a very difficult task and always involves arbitrary and unpleasant choices. There have been many attempts to quantify the impacts and emissions into a single unit — sometimes an environmental quality unit or more usually, dollars. (4,15,206-214, 234)

Developing and utilizing such an index system was not one of the tasks of this study. However, it seems appropriate to comment on possible methods to weigh the various impacts and emissions.

When comparing the emissions from a coal power system and a nuclear power system, for example, one is faced with the problem of comparing chemical and radiological pollutants. One method of doing this is to calculate dilution volumes. (208-212) Most air and water pollutants, whether radiological or chemical, have a maximum allowable ambient concentration set by government standards. The dilution volume is the amount of air or water that would be necessary to dilute a particular amount of emissions to the concentration set in the standard. Below are some examples of dilution volumes in air.

1.0 Curie of H-3 --- 5.0 million cubic meters

1.0 Curie of Pu-239 --- $1.7\ (10)^7$ million cubic meters

1.0 kilogram of SO_2 --- 12.5 million cubic meters

1.0 kilogram of NO_2 --- 10.4 million cubic meters

There are several problems with this method. Firstly, it is not at all clear that the different standards have been set with either accurate information or with the same criteria. Additionally, these standards do not consider the lifetime of the substances in the environment. They are only designed to regulate ambient levels and thus do not reflect how long the material will be in the environment and for what length of time the dilution will be necessary.

This may be very important when comparing radiosotopes with chemicals. A kg of SO_2 for example will require a dilution volume of 12.5 million cubic meters at first, but after a few hours or days will be completely degraded. A Ci of plutonium, on the other hand, would require $1.7(10)^7$ million cubic meters, but it does not degrade appreciably in any meaningful time span. Thus, should it remain in the air, the plutonium will indefinitely require this volume for dilution. Of course it is unlikely to remain suspended in the air, but the important point is that radioisotopes degrade at the rate of their radiation half-life and no faster while many chemical pollutants degrade quite quickly in the environment. Some chemical pollutants, such as toxic metals, may also have long environmental residence times. A further problem in using dilution volumes is that both radioisotopes and chemical pollutants often degrade into substances of equal or greater toxicity than the original substance. Finally, dilution volumes do not account for synergisms i.e. substances can act in concert to cause an effect much larger than the sum of the effects of each substance acting singly. The ultimate absurdity would be to have a liter of air in which all the thousands of possible pollutants are contained at their legal concentrations. The pollutants would effectively be diluting each other and the total environmental and health impact would be very uncertain.

Cautioning the reader to keep in mind the problems of using dilution volumes, we have compared the routine emissions of systems in table III-B-6.

Table III-B-6: Dilution Volumes for Complete Fuel Cycle [c]

Million cubic meters of air/MWeyr

Routine Emissions	Low Btu Gas/ Combined-Cycle	LMFBR
Chemicals	NO_2, SO_2, Part.	NO_2, SO_2, Part.
Dilution Volume	20,000-120,000	70.0 - 80.0
Radio-isotopes	Ra-226,228 [a]	H-3, Kr-85, Pu [b]
Dilution Volumes	0.02 - 0.7	65.0 - 7,000

a. Assumes 40% Ra-228, 60% Ra-226.

b. Assumes all release labelled Trans-Uranium is plutonium-239.

c. These values should be considered only as gross approximations (see text).

Only considers routine emissions.

Does not account for environmental lifetime of these materials.

We have provided a person-day loss figure for health impacts. This is often used to weigh the relative mortality and morbidity rates and to account for the average severity of the disabilities. Many studies convert person-days lost into a dollar figure as a method of comparing health impacts with other impacts. This may be a severe case of not seeing the forest because of the trees. What we should try to maximize is the quality of human life, not one particular resource. In many cases it is difficult to assess the impact of a particular loss or gain on the quality of life, e.g. the extinction of an animal species, but very few would argue that ill-health is not a debit under almost all situations. This should not be forgotten when ill-health costs are calculated. The days lost to a miner who has been killed cannot be returned to him by a government benefit check, even though accounted for in the overall economic tabulation. Health is not completely a buyable or salable commodity.

The development of accurate, relevant and usable indices should have a high priority. This report and others like it should be of value as input to the formulation of these indices.

III-B-7:
Global and Social Effects

There are a multitude of environmental effects associated with energy use and understood with varying degrees of inexactitude. Some of these effects may be important and, may overshadow the better understood effects listed in the tables in Appendices A - H.

Local, regional and global changes in climate have been associated with emissions of particulates, CO_2 and heat. However, little of a quantitative nature can be said about the dose-response relationships linking these pollutants and climatic change. (48)

Acid rain and long-term build-up of acid soil from air pollutants creates ecological and economic impacts of a magnitude yet to be precisely determined. Atmospheric build-up and food-chain concentration of radionuclides and other toxic materials may become a problem. (Some believe, for example, that the carcinogenic potential of tobacco is due to nuclear weapons fallout.) (Ref.235) Energy systems cause local changes in ecological relationships which may lead to undesirable perturbations of important biological systems. (49)

The impact of an increased environmental load of chemical and radionuclide mutagens on genetic disease and evolution is not understood. In addition, synergistic effects of pollutants may lead to more carcinogenesis and other diseases than would be estimated by examining each pollutant separately.

All of the above effects exist but the data are much too preliminary and scanty to make any definite conclusions about their magnitudes. All deserve close scrutiny so that we will be able to perceive any adverse effects before an over-dependence on a particular offending system makes orderly change difficult.

In addition, there is a variety of social effects associated with energy systems. Some of these effects can be predicted and observed and, with proper planning and allocation of resources, mitigated to a great extent. Others are not well understood or are not subject to obvious solution.

The construction and operation of power plants, mines and other facilities has an impact on local economics, social services, housing etc. especially in areas such as the western range states where there has been little development. There is also a competition for scarce resources (e.g. workers and water) needed for development. Land use and siting problems can be severe and be the cause of considerable local disruption and unrest.

The existence of fissle material in nuclear fuel cycles creates another type of social problem. The extent to which such material can be safeguarded against diversion attempts by criminal or terrorist groups is unknown, as is the liklihood of any group attempting such an anti-social act. In Appendices E - H we have listed the amounts of material suitable for making nuclear explosives. The difficulty of stealing material or using it to fabricate a nuclear explosive (or dispersal device) varies considerably between fuel cycle steps and cycles. We have not tried to detail these difficulties but only to list the amounts at each fuel cycle step.

In addition, to some extent, the use of nuclear power changes the likelihood of international nuclear conflict because of the ease in which nuclear reactor fuel and by-products can be used to make weapons. Nuclear energy cannot be divided neatly into electric power and weapons. Having one capability is to have the other. However, the extent to which unilateral decisions about nuclear power taken by the U.S.A. might influence other countries is not at all certain.

Altering the international demand for energy commodities such as petroleum, uranium and scarce metals for reactor construction might also push world political and economic patterns toward less stability.

These kinds of social, political and economic problems are potentially severe and a consideration of them should be brought into any full accounting of the impacts and costs of energy systems.

Finally, there are two more subtle social issues which need to be addressed. The first, mentioned briefly in section III-B-4, is risk distribution. In comparing alternative means to reach the same objective, as in the case of choosing between different electric power systems, the distribution of impacts over time, distance and population may be quite different in different systems. To merely total the impacts for each system does not provide enough information about when, where and to whom the impacts will occur.

Consider the choice between building a nuclear or coal-fired power plant. If one tries to compare the health impacts, the distribution of risks and impacts is so different in each system that it is difficult to understand the significance of the difference in the magnitude of impacts. Coal electric systems seem to have a relatively constant impact due to air pollution, mine cave-ins, etc. Nuclear power systems have relatively low routine impact but have a small chance of very large accidents which could kill and injure a large number of people. Should we build a system that will kill 30x persons (for example) in its lifetime with relative certainty or the other which might kill 100x but more likely will kill only x over its lifetime? (This is an over-simplification, for there is actually a series of possible nuclear power plant accidents ranging from very slight to very catastrophic.) The decision is not easy.

Most individuals who are asked to make decisions involving high severity/low probability outcomes are risk averse, i.e. they will not choose any alternative that has an appreciable chance of a big loss unless the chance of possible benefits is very much larger. Large institutions, such as governments, tend to be less risk averse, although there is evidence to show that they are also risk averse when faced with possible severities which would be as catastrophic to them as a much smaller loss would be to an individual. Nuclear power may be such a situation. Thus, although the average (expected value) impact of coal systems may be greater, the amount of social, economic and political disruption that would accompany the health damages incurred from a nuclear power plant accident may be at such a level that even governments will act in a risk averse manner and choose coal. The uncertainties and stakes may be too high for individual acting in groups to undertake. In addition, although such decisions are made by the group, the actual risks and benefits are not spread equally throughout the population. The coal miner and the person living near a nuclear or coal power plant have a much different risk than the city dweller living up-wind from all the plants. It is not clear that using the average risk is completely equitable.

Cost/benefit and risk/analysis approaches have been attempted over and over again (15,191,199-203) for these questions, but the basic questions of risk distribution and equity have not been solved.

The last social issue to be discussed here is a generalization of the risk distribution issues discussed above. This is the problem of time. Just as the time distribution of accident risk varies for different systems, the time distribution of other costs and impacts can have significant variations. Strip-mined land, nuclear waste, released radioisotopes and toxic metals all continue to exert costs and impacts well beyond the time the power systems that created them have been shut down. Irreversible commitments and depletion of resources also create impacts on the future. The use of economic discounting (to account for the opportunity cost of capital) does not always seem an equitable way to deal with these problems. Our responsibility to the future, or, in other words, the problems of inter-temporal equity, should be confronted.

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Abbreviations Used in References

AEC	Atomic Energy Commission
ANL	Argonne National Laboratories, Argonne, Illinois
BAT	Battelle Laboratories, Columbus, Ohio and Richland, Washington
BNL	Brookhaven National Laboratory, Upton, New York
BOM	Bureau of Mines
CEQ	Council on Environmental Quality
DOI	Department of the Interior
EPA	Environmental Protection Agency
EPP-Ford	Energy Policy Project of the Ford Foundation
ERDA	Energy Research and Development Administration
EPRI	Electric Power Research Institute, Palo Alto, California
FEA	Federal Energy Administration
FEA-PI	Federal Energy Administration, Project Independence Task Force Report
FPC	Federal Power Commission
HEW	Department of Health, Education and Welfare
JPL	Jet Propulsion Laboratory, Pasadena, California
NAE	National Academy of Engineering
NAS	National Academy of Sciences (NRCo: National Research Council)
NASA	National Aeronautics and Space Administration
NRC	Nuclear Regulatory Commission
ORNL	Oak Ridge National Laboratory, Oak Ridge, Tennessee
OST	Office of Science & Technology
UARL	United Aircraft Research Laboratories, East Hartford, Connecticut
CEP	Cornel Energy Project, Ithica, New York

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Appendices A - H

The bulk of the data collected in this study is presented in the following 24 tables. Unless otherwise stated, the costs, resource requirements, and impacts are stated per electrical magewatt-year (MWe-yr) net output at the power plant. Therefore, to calculate the impacts for a 1000-MWe plant operating at 75% capacity for one year, for example, the individual impacts listed in a table should be multiplied by 750. (See introduction to Chapter III for a discussion of scaling.) For one time items such as construction labor or materials, or power plant land, the quantity should be multiplied by 750 x lifetime which is usually 30 years unless noted otherwise. Power plant O & M cost is based on rated capacity and is in \$/MWe each year. This annual cost is \$/MWe-yr x MWe rated capacity of 10^3 MWe.

The range indicated for some costs and impacts results from the scatter of values in the literature. We have tried to adjust the values when possible to account for the differences due to different assumptions. In many cases there was not enough information available to evaluate all the assumptions and, in those cases where a large discrepancy still existed between sources, we have noted the original references directly. It is tempting to assign a probability distribution to the ranges. This would be improper, however, because in most cases the ranges are composed of a very few separate values which are not all independent. (The studies all quote each other.) (See Ref. 236 for another recent review.)

Unless otherwise noted, the data have been compiled from references 1 - 40 and most often from references 1 - 9.

The costs and impacts have been categorized in the table by fuel cycle step. The footnotes to the first table for each system (i.e. Tables A-1, B-1, etc.) contain descriptions of exactly which facilities and operations are included in each fuel cycle step.

Explanation of Symbols and Units

Most of the values are presented in exponential form:

For example, 2.9 - 5.9 -4 = 0.00029 - 0.00059

1.6 - 8.0 +4 = 16,000 - 80,000

-- A dash indicates that this box is not relevant to this system.

0 A zero indicates that there is an unknown but neglible impact or cost.

? A question mark indicates that the impact or cost may be important but its value is uncertain.

Tables 1:

Kwe	kilowatt electric
Mwe	megawatt electric
KwHe	kilowatt electric hour
MH	man hour
Mwth-yr	megawatt thermal year
MT	metric ton
m^2	square meter

M_2MT	million metric ton
m^2	square meter
Primary	Energy contained in the fuel in MWth-yr so that 1 MWe-yr is produced at the generating plant
Efficiency	Simple thermal of fuel efficiency (See Ref. 51-52 for a discussion of more sophisticated efficiency measures.)
Ancillary	Energy needed external to primary fuel (MWth-yr/MWe-yr)
Net Efficiency	Primary energy efficiency corrected for ancillary energy use assuming ancillary energy could be converted to electricity at total primary efficiency of specific approach

Tables 2:

NOx	nitrogen oxides
SOx	sulfur oxides
HC	hydrocarbons (includes aldehydes)
Other	mostly carbon monoxide except where noted
Solid, Radioactive	High level = greater than 10^6 x MPC Intermediate + 10^6 to 10^4 x MPC Low = 10^4 to 10 x MPC (see Refs. 3 and 189)

Tables 3:

Person-days lost: Calculated as 6000 days per death (premature as well as acute deaths) (Ref. 1), ~50 days per injury or illness & 100 days per cancer (except where noted).

Societal risk: Total number of deaths or disabilities expected per Mwe-yr in the entire country (except where noted).

Maximum Size: Estimated maximum for a facility, not in units of Mwe-yr.

Fissile material: Uranium 235 or 233 enriched to 20% or more and all plutonium 239 and 241.

The category marked "In Storage" refers to an assumed two month supply of fissile material at fabrication and reprocessing plants. The amount at reactors is the average fissile content over the fuel exposure period. To this could be added the fissile material in cooling ponds at reactor sites. The total material in storage is a measure of the fissile material which actually leaves the fuel cycle for this reactor and is sent to storage or sold to supply another reactor. The category, "In Transit" refers to fissile material which passes through fabrication and reprocessing plants. The total transit amount refers to the material which leaves the reprocessing plant for all destinations. All figures have the units of kilograms per Mwe-yr.

Table A-1: Coal with Lime Scrubber Flue Gas Desulfurization

COSTS and RESOURCE UTILIZATION			HARVESTING FUELS (a)	UPGRADING FUELS (b)	TRANSPORTING FUELS (c)	CONVERSION TO ELECTRICITY (d)	MANAGEMENT OF FINAL WASTE (e)	TOTAL	
COSTS	Power Plant Capital (\$/kwe)					(f) 4.04 +2			
	Power Plant O&M (\$/Mwe/yr)					(x) 1.31 +4			
	Fuel (mills/kwHe) (g)		1.07 1	5.27 -1	3.75 0	1.50 +1	(n)		
	Electricity (mills/kwHe) (g)					3.17 +1			
	Fuel Cycle Capital (\$/kWe)		(h) 6.83 +1	(j) 3.11 0	(k) 4.71 +1		(n)	1.19 (y) +2	
	Fuel Cycle O&M (\$/Mwe-yr)		(h) 3.43 +4	(j) 1.14 +3	(j) 1.21 +4		(n)	4.75 +4	
LABOR MH/MWe-yr	CONSTRUCTION (k)	Engineering	7.16 0	(k)	2.60 0	4.05 +1	(o)	5.03 +1	
		Field Super. & Adm.	7.01 0	(k)	2.68 0	3.50 +1	(o)	4.47 +1	
		Field Unskilled manual	2.89 0	(k)	5.36 0	5.22 +1	(o)	6.05 +1	
		Field Skilled manual	3.25 +1	(k)	1.59 +1	3.01 +2	(o)	3.49 +2	
		TOTAL	4.96 +1	(k)	2.65 +1	4.29 +2	(o)	4.91 +2	
	O&M		(h) 1.62 +3	(i) 4.93 +1	(l) 9.21 +1	(m) 4.07 +2	(o)	2.17 +3	Net (w)
ENERGY (J)	Primary	(Mwth-yr/MWe-yr)	2.85 0	2.85 0	2.75 0	2.71 0	--	2.85 0	
		Fuel efficiency	1.00 0	9.64 -1	9.85 -1	3.70 -1	--	3.51 -1	3.44 -1
	Ancillary	(Mwth-yr/MWe-yr)	2.13 -2	6.52 -3	3.50 -2	0	--	6.28 -2	
MATERIALS MT/MWe-yr	CONSTRUCTION (k) METALS	Structural	4.93 -1	(k)	2.89 -2	7.43 -1	(o)	1.26 0	
		Pipes	1.64 -1	(k)	0	9.30 -2	(o)	2.57 -1	
		Major Equipment	6.57 -1	(k)	8.67 -1	8.84 -1	(o)	2.41 0	
		Other Equipment	0	(k)	5.78 -2	3.58 -1	(o)	4.16 -1	
		TOTAL	1.31 0	(k)	9.54 -1	2.08 0	(o)	4.34 0	
		Concrete	0	(k)	0	6.82 0	(o)	6.82 0	
	O&M		--	--	--	(p) 2.47 +2	--	2.47 +2	
LAND (q) m2/MWe-yr	Temporarily Committed	TOTAL	(r) 4.5 +3	(s) 3.36 +1	(t) 3.49 +2	(u) 1.08 +2	(s) 1.08 +2	4.99 +3	
		Undisturbed	0.6-3.0 +3	0	2.33 +2	0	0	0.8-3.2 +3	
		Disturbed	1.5-3.9 +3	3.36 +1	1.16 +2	1.08 +2	1.08 +2	1.9-4.3 +3	
	Permanently Committed		0	0	0	0	0	0	
WATER (v)	(10^6 Liters/MWe-yr)		0	3.80 -1	0	1.44 +1	2.30 0	1.71 +1	

Table A-1 Footnotes

a. Except for "fuel cost", quantities given are for Northern Appalachian deep-mined coal. Northwestern surface mines were considered as an alternative source of coal, and resource utilization for this type of mining is included in the appropriate footnotes below. Mine life is assumed to be 20 years.

b. Only about 2/3's of the Northern Appalachian coal production is cleaned: quantities given represent average quantities for the sum of the cleaned and uncleaned portions. Northwest surface-mined coal is typically not cleaned. Facility lifetime assumed is 20 years.

c. Although some coal is transported by water (barge), about 70% is shipped by rail: quantities given here assume all coal is shipped by rail, with a 50-50 split between the unit train and non-unit train modes, reflecting current trends toward the unit train concept. National average coal (Table A-2, note g) is considered at this and subsequent stages. Train lifetime assumed is 30 years.

d. Quantities given are for a coal-steam power plant with sulfur removal from the stack gas by wet lime scrubbing and natural draft evaporative cooling tower for national average coal.

e. Represents quantities attributable (where available) to on-site disposal of bottom ash, recovered fly ash and lime sludge for national average coal.

f. From Reference (21), which uses methodology given in Reference (27). This figure includes interest during construction at 10.5% as well as 6% inflation rate. The net or real interest rate is 4.25% (1.105/1.06) for 3.5 yrs, i.e., \$349/kW x $1.0425^{3.5}$ = \$404/kW. This expresses costs prior to plant startup in mid-1974 (1974\$).

g. In accordance with economic groundrules developed by JPL (28), the contribution of fuel cost to the cost of generating electricity is equal to the present value of the cost of fuel purchased over the life of the plant multiplied by the annual capitalization factor.

The most current data on the cost of coal to electric utilities from Reference (31), is 88.9¢/million Btu for December, 1974. To adjust this to mid-1974 dollars, the increase from the June 1974 price (69.5¢/million Btu) was deflated by the increase in the Consumer's price index (6%) from June through December, 1974, giving a mid-1974 dollar cost of coal of 83.9¢/million Btu. The general expression for electricity cost given in Reference (28) is:

$$\left[\frac{\text{Electricity Cost}}{\text{KwHe}}\right] = \left[\frac{\text{Capital Charges}}{\text{KwHe}}\right] + \left[\frac{\text{O \& M Costs}}{\text{KwHe}}\right] + \left[\frac{\text{Fuel Cost}}{\text{KwHe}}\right]$$

$$EC = \frac{CRF \times IT}{8.76\ PL} + \frac{CRF \times PVF}{8.76\ PL}\left(.05\ IT + N\right) + \frac{CRF \times PVF}{8.76\ PL}\left(\frac{29.9\ GPL}{\eta}\right)$$

where:

EC = electricity cost in Mills/KwHe

CRF = capital recovery factor = $\frac{r(1+r)^n}{(1+r)^n-1}$

r = the annual return on borrowed capital

n = the number of years for pay back (usually equals expected plant life)

IT = plant capital cost in dollars, including interest during construction

0.05IT = Factor accounts for annual operating cost due to insurance, depreciation, profit, taxes, etc.

G = fuel cost in $\$/10^6$ BTU

P = plant peak power in KW

L = annual load factor

η = efficiency of power plant = (output electrical energy/input thermal energy).

N = plant O & M costs in \$/year.

PVF = the present value factor = the present value of a stream of costs growing at an annual rate of (1 + i), with the first payment of

$$\text{one dollar made today} = \frac{1}{g-i}\left[1 - \left(\frac{1+i}{1+g}\right)^n\right](1+g)$$

i = Long-term annual inflation rate (0.06).

g = the annual discount rate.

In this report it is assumed for the coal systems that:

r = 0.105 (with 75% debt financing at 9% and 25% equity financing at 15%)

n = 30 years CRF = 0.1105 PVF = 17.5

P = 10^6 Kw, $L = 0.75$, $\eta = 0.37$ $g = r = 0.105$

Therefore the electricity cost equation may be written as:

Equation A-1: Capital Cost O & M Cost Fuel Cost

$$EC = 1.69 \times 10^{-8} \times IT + 2.97 \times 10^{-7} \times (0.05\ IT + N) + 17.9\ G$$

In the present case:

IT = 4.04×10^8 (from first row of table: 404\$/kWe x 10^6kWe)

G = 0.839\$/MBtu (from second paragraph of the footnote).

and N = 1.31×10^7 \$/yr (from second row of table: 1.31×10^4\$/MWe/yr x 10^3MWe)

$$\therefore EC = \underset{\text{capital}}{6.83} + \underset{\text{O \& M}}{9.89} + \underset{\text{fuel}}{15.0} = 31.70 \text{ mills/KwHe}$$

Therefore the total contribution of the cost of fuel to the cost of electricity for the coal-scrub system is 15 mills/KwHe. The portion of this cost attributable to transport was calculated from Reference (21), and the portion due to coal cleaning from Reference (4).

h. From Reference (57), assuming 1.03 MMT/yr mines. From Reference (60) the fuel cycle capital cost for a Northwestern surface mine is $\$2.41 \times 10^4$/Mwe-yr, O & M cost $\$1.26 \times 10^4$/Mwe-yr, and O & M labor requirement, 1.84×10^2 MH/Mwe-yr. (based on a 9.2 MMT/yr northwestern surface mine). Deferred mine capital investments were discounted at 12% per annum as per source documents.

i. From Reference (4).

j. From References (1) & (7). Energy numbers are for national average coal throughout. Electricity requirements are converted to thermal energy requirements using 37% power plant thermal efficiency and 90% transmission thermal efficiency.

k. From Reference (8). Construction materials and construction labor requirements for coal cleaning are included in the corresponding mining totals. For surface mining the construction labor requirements are: Engineering = 1.13 MH/MWeyr, Field Supervision = 3.76 MH/MWeyr, Field Skilled Manual = 1.90 MH/MWeyr and Field Unskilled Manual = 16.9 MH/MWeyr for a total of 23.7 MH/Mwe-yr. Construction materials required would be: Structural = 4.47 10^{-2} MT/MWeyr, Major Equipment = 0.26 MT/MWeyr for a total metals requirement of 0.3 MT/Mwe-yr. Those desiring a more detailed breakdown of these requirements are referred to References (32), (33), (34) (35), and (37). However, the most complete detailed breakdown of construction labor and materials, as well as O & M costs and labor requirements for all our study systems except the fluidized-bed system, is in Ref. (36). To calculate total material or manhours, multiply data in table by 750 MWe x 30 years.

l. from Reference (33).

m. from Reference (7).

n. included in power plant O & M cost.

o. included in corresponding power plant quantities.

p. lime requirement for scrubber.

q. derived from References (1), (2), (3), (4), (7) and (8).

r. Refers to land undermined/Mwe-yr, approximately 1/3 to all of which is affected by subsidence. For strip mining of Northwestern Coal approximately (1.4 - 2.1) x 10^3 m^2/Mwe-yr. are disturbed by strip mining. This impact is, however, very dependent on the thickness of the coal seams mined (they are typically quite thick in the Northwest up to 100 ft and about 10 times thicker than Eastern coal); for the national average strip mine about 2.5 x 10^3MWe-yr are distributed, with some regions (e.g., Appalachian) averaging as high as 3.2×10^4 m^2/Mwe-yr. Northwestern surface mined coal is typically not cleaned due to relatively low sulfur content. Deep mine openings are assumed to be backfilled to prevent permanent land committment. For surface mines some (relatively small) permanent land use is likely to be associated with the pit. If the mines are not revegetated properly, a dust bowl can be created and the temporarily distributed land could be considered more in the permanently committed category.

s. Actually some land is probably temporarily committed and not disturbed, it is assumed here that the only such land is for future waste storage (i.e. eventually disturbed).

t. This figure assumes a rail right of way of 50 ft; we assume about 1/3 of this is actually occupied by the rail bed.

u. Actually some of the plant site is undoubtedly undisturbed, but the undisturbed portion of the total is likely much less than for nuclear facilities, which require sizable exclusion zones and for which the committed, but undisturbed land use category is more relevant.

v. Primarily from references (3) and (7).

w. Net efficiency equals total primary efficiency corrected for ancillary energy use. For example, net efficiency = 1 MWe/(2.85 + 0.063) = 0.344.

x. Power plant O + M cost is based on installed capacity and is in \$/yr. Thus, the label is \$/MWe-yr. To find O & M cost per year, multiply by nameplate rating in MWe.

y. The total capital charge can be found by adding the plant and fuel capital charges. The total fuel capital charge is multiplied by the plant load factor, 0.75, since the data in the table is based on cost per kWe installed capacity. The total capital charge for both the coal and utility industry is: $(\$/kWe)_{TOTAL}$ = 404 + 0.75 x 119 = 493\$/kWe.

Table A-2: Coal with Lime Scrubber Flue Gas Desulfurization

Environmental Releases			HARVESTING FUELS (a)	UPGRADING FUELS (d)	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY (g)	MANAGEMENT OF FINAL WASTE	TOTAL
AIR	Non-Radioactive (metric tons/MWe-yr)	NO_x	4.0 -2	1.1 -1	1.9-2.8 -1	12.9-25.3 0	0	1.3-2.6 +1
		SO_x	2.9 -3	7.6 -2	1.7-2.5 -1	1.1-3.8 +1	0	1.1-3.8 +1
		Particulates	1.4 -3	0.8-3.0 0	(f)2.1-34.0 0	(g)1.5-3.8 0	(k) ?	4.4-40.8 0
		HC	4.6 -3	0	1.6-2.3 -1	5.2 -1	0	6.8-7.5 -1
		Toxic Metals	0	0	0	(h) 1.6-2.0 -2	(k) ?	1.5-2.0 -2
		Other (o)	2.4 -2	0	2.7-4.8 -1	2.9-17.0 -1	?	5.8-22.0 -1
		Total	7.3 -2	1.0-3.2 0	2.9-35.2 0	2.6-6.9 +1	?	2.9-10.7 +1
	Radioactive (curies/MWeyr)	Rn	--	--	--	--	--	--
		H-3	--	--	--	--	--	--
		Kr-85	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Other	--	--	--	(n)3.5-27.0 -5	--	3.5-27.0 -5
		Total	--	--	--	3.5-27.0 -5	--	3.5-27.0 -5
WATER	Non-Radioactive (MT/MWe-yr)	Silt	8.9 -2	(e)0.4-116.0 0	0	0	(l) ?	0.5-116.1 0
		Other (p)	(b)0.6-50.0 +1	(e)0-7.2 0	0	(i)1.5-4.9 0	?	7.5-512.1 0
		Total	0.6-50.0 +1	0.4-123.2 0	0	1.5-4.9 0	?	8.0-628.1 0
	Radioactive (curies/MWeyr)	H-3	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Other	--	--	--	--	--	--
		Total	--	--	--	--	--	--
SOLID	Non-Radioactive	(MT/MWe-yr)	(c)1.3-1.8 +2	3.2-6.2 +2	0	(j)1.2-1.3 +3	(m) ?	1.7-2.1 +3
	Radioactive (curies/MWeyr)	High Level (liters/MWeyr)	--	--	--	--	--	--
		Fission Prod.	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Total	--	--	--	--	--	--
		Low Level (liters/MWeyr)	--	--	--	--	--	--
		Intermediate (liters/MWeyr)	--	--	--	--	--	--
		Buried Solid (m^3/MWeyr)	--	--	--	--	--	--
		Tailings (curies/MWeyr)	--	--	--	--	--	--
THERMAL DISCHARGE		(Mwth-yr/MWe-yr)	0	0	0	1.7 0	0	1.7 0

Table A-2: Footnotes

a. These values are for eastern underground coal mining.

For western surface mining:

Air:	NOX	1.1 -1 MT/MWe-yr	Water:	Silt	3.7 - 4.0 MT/MWe-yr
	SOX	8.1 -3		Other	8.6
	Part.	7.3 -2			
	HC	1.3 -2	Solid:		1.09 - 60.0 +2 (high end includes overburden) MT/MWe-yr
	Other	7.0 -3			

Western coal is not cleaned. See references 58, 59, 61.

b. High end of range includes no acid control. See note c.

c. High end of range includes solids from acid control. See note b.

d. Two thirds of the coal is physically cleaned to remove 40% of the total sulfur. At the cleaning plant a 90% removal efficiency is assumed for coal burned on site (4).

e. High values are for releases without environmental controls. (3,4) Over 95% of this release is composed of suspended coal in "black water" from the cleaning plant.

f. 0.1 - 1.0% loss in transport. If the higher number is more accurate, this is the source of the largest amount of particulates by weight in all the coal cycles. However, because of the differences in size distributions it may not be the most important in terms of health effects. (129)

g. The ranges of emissions for the power plant correspond to the following ranges of characteristics for "national average coal":

2.5 - 3.0% sulfur
10 - 12% ash
11,600 - 12,500 Btu/lb.

The range in power plant characteristics: (65-86)

80 - 90% removal of sulfur in scrubber
99 - 99.5% removal of particulates by weight
37% thermal efficiency

0 - 67% of the coal is cleaned to remove 40% of the total sulfur. NOx emissions correspond to the emissions from the best available new boilers (0.7 lb/million Btu) to new boilers with combusion modifications (0.35 lb/million Btu) (15,77-79, 85).

h. See ref. 5.

i. From power plant and cooling tower.

j. 65% sludge and 35% ash.

k. There could be air pollution from burning coal mine refuse banks (see table A-3). There could also be air pollution (mostly particulates) from ash and sludge transport and disposal.

l. The sludge has a pH of about 9, 0.3 - 1.4 ppm toxic metals, 35-55% solids and would greatly exceed most water quality standards if released. See section III-B-5. (65, 87-90)

m. The total volume of waste could be reduced by one third to one half if the sludge were to be dewatered and compacted. It could also be used as a fill material for open space or construction depending on the degree of compaction and dewatering. (88, 90)

n. See references 5, 80, 209.

o. Primary CO except where noted.

p. Biologic oxidation demand, dissolved solids and alkalinity are not noted, but suspended solids, and acidity are included.

q. Dissolved solids from cooling tower drift could be added and is approximately 0.3 MT/MWe-yr.

Table A-3: Coal with Lime Scrubber Flue Gas Desulfurization.

Health Effects			HARVESTING FUELS (a)	UPGRADING FUELS (l)	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTAL
OCCUPATIONAL (per MWeyr)	Accidental (k)	Death	0.8-2.2 -3	2.1-3.5 -5	1.6-5.0 -3	1.3-9.0 -5	(h) ?	2.4-7.5 -3
		Injury	0.4-1.1 -1	1.4-2.7 -3	1.3-4.8 -2	1.6-8.5 -3	?	5.6-16.9 -2
		Prs-days lost	0.7-2.0 +1	2.0-3.5 -1	(d) 1.0-3.5 +1	1.6-9.7 -1	?	1.8-5.6 +1
	Disease	Death	(b) 0-5.9 -5	0	0	0	0	0-5.9 -5
		Disability	(b) 5.5-8.2 -4	0	0	0	0	5.5-8.2 -4
		Prs-Days	0.3-4.0 -1	0	0	0	0	0.3-4.0 -1
PUBLIC (per MWeyr)	Accidental (k)	Death	0	0	(e) 7.3 -4	0	0	7.3 -4
		Injury	0	0	1.6 -3	0	0	1.6 -3
		Prs-days	0	0	4.5 0	0	0	4.5 0
	Disease	Death	0	0	0	(f) .02-3.6 -2	(i) 0-1.3 -2	.02-4.9 -2
		Disability	0	0	0	(f) 0.1-21.6 +1	?	0.1-21.6 +1
		Prs-days	0	0	0	(f) .06-13.5 +2	?	.06-13.5 +2
LARGE ACCIDENTS	Maximum Size	Death	$10-10^2$	0	?	(g) ?	0	--
		Disability	?	0	?	?	0	--
	Societal Risk	Death/MWeyr	(c) 10^{-6}	0	?	?	0	?
		Disability	?	0	?	?	0	?
GENETIC RISK	TOTAL (Prs-rem Equiv./MWeyr) (j)		?	?	?	?	?	?
SOCIAL EFFECTS	Fissile Material (kg/MWeyr)	In Storage	--	--	--	--	--	--
		In Transit	--	--	--	--	--	--

Table A-3: Footnotes

a. Underground eastern coal mining.

For western surface mining: Accidental deaths: 2.2 - 4.1 $(10)^{-4}$/MWeyr

Injuries 3.4 - 15.0 $(10)^{-3}$/MWe-yr

There is a large difference between the safest and most dangerous mines and a great possibility for improvement in the average rate. At present the best mines have accident rates of 10% of the national average rates. (Average is 50.2 injuries/10^6 miner hours while low is 5.3 injuries/10^6 miner hours.) Thus, if the average were to approach the best now available, the injuries would be substantially reduced. For trends in underground accident rates:(24,25,137)

b. This assumes the present dust levels are inforced (see Section III-B-1).

Other assumptions:

11600 - 12500 BTU/lb coal

10.2 - 14.2 MT/miner-day

220 miner day/yr

Dose Response - Ref. (25)

Low End Range - no complicated CWP (coal workers pneumoconcosis) or death

High End Range - ratio of 1 to 14 death to disease as in present rates

At present the rates are as follows based on Reference 10 and used as an upper limit:

per MWeyr	
0 - 9.3 -3	death
2.7 - 12.9 -2	disability
1.4 - 62.3	person-days lost for death and disability

for 1000 MWe plant in 1 year	
0.5 - 7.0	PMF (progressive massive fibrosis or complicated CWP)
20.0	CWP (coal workers pneumoconcosis)
0-70	Other effects (e.g in miner's families)
0-7	Death

Based on Reference 2 and used as a lower limit:

$\left.\begin{array}{l}\text{2.9 simple CWP}\\ \text{1.3 complicated CWP}\\ \text{1.8 suspected CWP}\end{array}\right\}$ for 1000 MWe plant in 1 year

See Section III-B-1 for a discussion of the future rates if present dust level standards are maintained. (25).

c. 10^{-3} chance of 25+ persons killed in a mine accident. (10) One 1000-Mwe plant uses about $5(10)^{-3}$ of the present coal production.

d. 93 days/injury (1)

e. From rail transport of coal.

f. SOx pollution only (15). Other pollutants such as NOx, ozone and CO also have an effect, but are not included, but health effects are based on SOx in presence of airborne particulates.

MT Sox/yr	Remote Site	Urban Site	
11	$0.17 - 3.4(10)^{-3}$	$0.05/- 1.0(10)^{-2}$	(Premature Deaths/MWeyr)
38	$0.16 - 1.2(10)^{-2}$	$0.18 - 3.6(10)^{-2}$	

This range in the table includes a factor of 20 uncertainty in dose response relationship.

Illness: Chronic respiratory diseases = 5 days lost

Asthma attacks = 1 day lost

Respiratory diseases in children = 1 day lost

Aggravated person-days of heart-lung disease counted only as person-days lost.

These numbers were calculated directly from the values in ref. 15 which are subject to much debate. Please see references (10, 122-128, 132).

There may also be carcinogens (130, 131).

g. There does not seem to be any large-scale accident which might occur in a coal-fired power plant although many kinds of fires, explosion etc. could cause severe damage to the plant and many casualties among workers. (205)

h. There would be some occupational accidents involved in the handling of sludge and ash.

i. Air pollution from burning coal mine tailings banks (10). In addition, water pollution from sludge ponds could have an effect e.g. on cardiovascular disease and infant mortality rates, if drinking water supplies were affected. (140). See Table A-2 notes k-m.

j. There is evidence that some chemical emissions from fossil fueled power systems may have a mutagenic potential. The specific compounds, the routes of exposure and the dose/response relationships are not understood. Ideally it would be desirable to be able to measure both the genetic effects of chemicals and radiation in a common unit such as the person-rem equivalent (213). This is well beyond our current ability.

k. 6000 PDL/death from Ref. (1).

l. 2/3 of coal is processed (Ref. 1, 2, 10).

Table B-1: Coal with Fluidized-Bed Combustion

COSTS and RESOURCE UTILIZATION			HARVESTING FUELS (a)	UPGRADING FUELS (a)	TRANSPORTING FUELS (a)	CONVERSION TO ELECTRICITY (b)	MANAGEMENT OF FINAL WASTE (c)	TOTAL
COSTS	Power Plant Capital ($/kWe)					(d) 3.02 +2		
COSTS	Power Plant O&M ($/MWe/yr)					(e) 8.41 +3		
COSTS	Fuel (mills/kWH) (f)		1.07 +1	5.27 +1	3.75 0	1.50 +1	(g)	
COSTS	Electricity (mills/kWHe) (f)					2.71 +1		
COSTS	Fuel Cycle Capital ($/kWe)		4.76 +1	4.64 +0	4.71 +1		(g)	9.93 +1
COSTS	Fuel Cycle O&M ($/MWe-yr)		3.43 +4	1.70 +3	1.21 +4		(g)	4.81 +4
LABOR MH/MWe-yr	CONSTRUCTION (h)	Engineering	7.16 0	(a)	2.60 0	?	?	?
LABOR MH/MWe-yr	CONSTRUCTION (h)	Field Super. & Adm.	7.01 0	(a)	2.68 0	?	?	?
LABOR MH/MWe-yr	CONSTRUCTION (h)	Field Unskilled manual	2.89 0	(a)	5.36 0	?	?	?
LABOR MH/MWe-yr	CONSTRUCTION (h)	Field Skilled manual	3.25 +1	(a)	1.59 +1	?	?	?
LABOR MH/MWe-yr	CONSTRUCTION (h)	TOTAL	4.96 +1	(a)	2.65 +1	?	?	?
LABOR MH/MWe-yr	O&M		1.62 +3	7.36 +1	9.21 +1	(i) 4.07 +2	(i)	2.19 +3
ENERGY	Primary	(MWth-yr/MWe-yr)	2.85 0	2.85 0	2.75 0	2.71 0	--	2.85 0 Net
ENERGY	Primary	Fuel efficiency	1.00 0	9.64 -1	9.85 -1	3.70 -1	--	3.51 -1 (3.44 -1)
ENERGY	Ancillary	(MWth-yr/MWe-yr)	2.13 -2	6.52 -3	3.50 -2	0	--	6.28 -2
MATERIALS MT/MWe-yr	CONSTRUCTION (i) METALS	Structural	4.93 -1	(a)	2.89 -2	?	?	?
MATERIALS MT/MWe-yr	CONSTRUCTION (i) METALS	Pipes	1.64 -1	(a)	0	?	?	?
MATERIALS MT/MWe-yr	CONSTRUCTION (i) METALS	Major Equipment	6.57 -1	(a)	8.67 -1	?	?	?
MATERIALS MT/MWe-yr	CONSTRUCTION (i) METALS	Other Equipment	0	(a)	5.78 -2	?	?	?
MATERIALS MT/MWe-yr	CONSTRUCTION (i) METALS	TOTAL	1.31 0	(a)	9.54 -1	?	?	?
MATERIALS MT/MWe-yr	CONSTRUCTION (i)	Concrete	0	(a)	0	?	?	?
MATERIALS MT/MWe-yr	O&M		--	--	--	(j) 4.51 +1	--	4.51 +1
LAND m^2/MWe-yr	Temporarily Committed	TOTAL	4.5 +3	5.02 +1	3.49 +2	(k) 1.08 +2	(k) 4.08 +1	4.90 +3
LAND m^2/MWe-yr	Temporarily Committed	Undisturbed	0.6-3.0 +3	0	2.33 +2	0	0	0.8-3.2 +3
LAND m^2/MWe-yr	Temporarily Committed	Disturbed	1.5-3.9 +3	5.02 +1	1.16 +2	1.08 +2	4.08 +1	1.8-4.2 +3
LAND m^2/MWe-yr	Permanently Committed		0	0	0	0	0	0
WATER	(10^6 Liters/MWe-yr)		0	3.80 -1	0	(k) 1.44 +1	(k) 2.30 0	1.71 +1

Table B-1: Footnotes

a. Since a 37% power plant thermal efficiency and a 75% power plant capacity factor are assumed here as for the coal-scrub system, the harvesting fuels, upgrading fuels and transporting fuels quantities are precisely the same as those given in Table A-1.

b. Quantities given are for a coal fluidized-bed boiler power plant with sulfur removal by regenerative dolomite absorption and a natural draft evaporative cooling tower, burning national average coal. Assumed plant thermal efficiency is 37%, capacity factor, 75% and plant life, 30 years.

c. Represents quantities attributable (where available) to on-site disposal of bottom ash, recovered fly ash and dolomite sludge.

d. In Reference (13), the cost of a fluidized-bed boiler power plant was estimated at \$192/kw in January, 1970 dollars, excluding interest during construction and escalation; assuming interest during construction for 2 years at 10.5%/year as well as 6% long-term inflation. The net interest rate is 4.25%/year and we get \$209/kW in January 1970 dollars. Adjusting to 1974 dollars using the Handy-Whitman index for steam-electric power plant construction (Ref. (38)), we get \$302/kW. Westinghouse is updating its cost estimates for their fluidized-bed boiler design as part of the NASA-ERDA-NSF Energy Conversion Alternative Systems (ECAS) study and the results of this work will be published in due course (42).

e. In Reference (1) conventional O & M costs of 1.28 mills/kWHe in 1974 dollars are implied. This corresponds to \$8.41 x 10^3/MWe-yr.

f. Coal costs are the same as given in Table A-1 and expanded upon in footnote g. of that table. We may also use equation (A-1) in that footnote to calculate electricity costs. For the present system:

$$IT = 3.02 \times 10^8 \quad \text{(from the first line of Table B-1)}$$

$$G = .839 \quad \text{(from Table A-1, footnote g.)}$$

and $$N = 8.41 \times 10^6 \quad \text{(from the second line of Table B-1)}$$

$$\therefore EC = \underset{\text{capital}}{5.10} + \underset{\text{O \& M}}{6.98} + \underset{\text{fuel}}{15.00} = 27.10 \frac{\text{mills}}{\text{KwHe}}$$

g. These costs are incorporated into the power plant O & M cost.

h. Although power plant construction material and labor requirements were not found for this system, the boiler itself is considerably smaller than a conventional steam boiler because it operates at higher pressure. Based on the relative direct capital costs a 20% reduction in construction materials seems plausible. The shorter construction lead time and use of a prefabricated boiler could imply construction manpower up to 25% less than for the coal-scrub system.

i. Power plant O & M labor requirements assumed identical to those for the coal scrub system, and include personnel required for waste disposal.

j. For a regenerative desulfurization system only 17% of the absorbent material required for the once-through system is necessary (Ref. (1)).

k. Land and water requirements are assumed to be identical to those for the coal scrub system except 83% less land is required for sludge disposal because a regenerative desulfurization system is employed. See also References (1) and (3) for land use, where smaller numbers are given, but likely exclude buffer zones.

Table 8-2: Coal with Fluidized-Bed Combustion

Environmental Releases			HARVESTING FUELS (a)	UPGRADING FUELS (d)	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY (g)	MANAGEMENT OF FINAL WASTE	TOTAL
AIR	Non-Radioactive (metric tons/MWe-yr)	NO_x	4.0 -2	1.1 -1	1.9-2.8 -1	2.6-8.1 0	0	2.9-8.5 0
		SO_x	2.9 -3	7.6 -2	1.7-2.5 -1	5.4-19.0 0	0	5.6-19.3 0
		Particulates	1.4 -3	0.8-3.0 0	(f) 2.1-34.0 0	5.9-38.0 -1 (n)	(i) ?	3.5-40.8 0
		HC	4.6 -3	0	1.6-2.3 -1	0	0	1.6-2.3 -1
		Toxic Metals	0	0	0	0.9-2.0 -2	(i) ?	0.9-2.0 -2
		Other	2.4 -2	0	2.7-4.8 -1	2.9-17.0 -1	?	5.8-22.0 -1
		Total	7.3 -2	1.0-3.2 0	2.9-35.2 0	9.2-25.7 0	?	1.3-6.4 +1
	Radioactive (curies/MWeyr)	Rn	--	--	--	--	--	--
		H-3	--	--	--	--	--	--
		Kr-85	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Other	--	--	--	2.1-27.0 -5	--	2.1-27.0 -5
		Total	--	--	--	2.1-27.0 -5	--	2.1-27.0 -5
WATER	Non-Radioactive (MT/MWe-yr)	Silt	8.9 -2	(e) 0.4-116.0 0	0	0	(j) ?	0.5-116.0 0
		Other	(b) 0.6-50.0 +1	(e) 0-7.2 0	0	1.5 0	(j) ?	7.5-508.7 0
		Total	0.6-50.0 +1	0.4-123.2 0	0	1.5 0	?	8.0-624.7 0
	Radioactive (curies/MWeyr)	H-3	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Other	--	--	--	--	--	--
		Total	--	--	--	--	--	--
SOLID	Non-Radioactive	MT/MWe-yr)	(c) 1.3-1.8 +2	3.2-6.2 +2	0	(h) 4.5-5.7 +2	(k) ?	9.1-13.7 +2
	Radioactive (curies/MWeyr)	High Level (liters/MWeyr)	--	--	--	--	--	--
		Fission Prod.	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Total	--	--	--	--	--	--
		Low Level (liters/MWeyr)	--	--	--	--	--	--
		Intermediate (liters/MWeyr)	--	--	--	--	--	--
		Buried Solid (m^3/MWeyr)	--	--	--	--	--	--
		Tailings (curies/MWeyr)	--	--	--	--	--	--
THERMAL DISCHARGE (MWth-yr/MWe-yr)			0	0	0	1.7 0	0	1.7 0

Table B-2: Footnotes

a-f. See notes a-f in Table A-2.

g. Ranges of emissions correspond to coal of:

2.5 - 3.0% sulfur

10 - 12% ash

11,600 - 12,500 Btu/lb.

Power plants with:

90 - 95% removal of sulfur (91-98)

99 - 99.8% removal of particulates by weight (4, 13, 92)

37% thermal efficiency

7% of the coal goes to regeneration system, 93% to boiler (equivalent to 39.8% efficiency of fluidized-bed boiler.)

0 - 67% of the coal is physically cleaned to remove 40% of the sulfur.

HC from ref. 1.

Toxic metals and radioactive emissions assumed to be controlled to the same extent as particulates.

80% of SOx from boiler and the rest from the dolomite regeneration and sulfur recovery plants. (1)

The range in NOx emissions is taken from refs. 4, 13, 92 . Ref. 15 uses a range of 3.7 - 6.3 MT/Mwe-yr.

The potential thermal efficiency is much higher. See chapters II and III as well as ref.13 and 92.

An additional 0.3 MT of dissolved solids from cooling tower drift could be added.

h. 300 - 380 MT ash

160 - 190 MT dolomite (1)

Sulfur recovered is not included. If 70% of the sulfur is recovered, uncleaned 3% sulfur coal could produce about 60 MT/Mwe-yr.

i-k. See notes k-m of Table A-2.

l-n. See o-q of Table A-2.

Table B-3: Coal with Fluidized-Bed Combustion

Health Effects			HARVESTING FUELS (a)	UPGRADING FUELS (i)	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTAL
OCCUPATIONAL (per MWeyr)	Accidental	Death	0.[illegible]-2.2 -3	2.1-3.5 -5	1.6-5.0 -3	(f) 0.6-1.5 -4	(i) ?	2.4-7.5 -3
		Injury	0.4-1.1 -1	1.4-2.7 -3	1.3-4.8 -2	(f) 2.9-5.1 -3	?	5.6-16.9 -2
		Prs-days lost	0.7-2.0 +1	2.0-3.5 -1	(d) 1.0-3.5 +1	6.1-11.6 -1	?	1.8-5.6 +1
	Disease	Death	(b) 0-5.9 -5	0	0	0	0	0-5.9 -5
		Disability	(b) 5.5-8.2 -4	0	0	0	0	5.5-8.2 -4
		Prs-Days	0.3-4.0 -1	0	0	0	0	0.3-4.0 -1
PUBLIC (per MWeyr)	Accidental	Death	0	0	(e) 7.3 -4	0	0	7.3 -4
		Injury	0	0	1.6 -3	0	0	1.6 -3
		Prs-days	0	0	4.5 0	0	0	4.5 0
	Disease	Death	0	0	0	(g) .08-18.0-3	(j) 0-1.3 -2	.08-31.0 -3
		Disability	0	0	0	(g) .05-10.8+1	?	.05-10.8 +1
		Prs-days	0	0	0	0.4 -67.5+1	?	0.4-67.5 +1
LARGE ACCIDENTS	Maximum Size	Death	$10-10^2$	0	?	(h) ?	0	--
		Disability	?	0	?	?	0	--
	Societal Risk	Death	(c) 10^{-6}	0	?	?	0	?
		Disability	?	0	?	?	0	?
GENETIC RISK	TOTAL (k) (Prs-rem Equiv./MWeyr)		?	?	?	?	?	?
SOCIAL EFFECTS	Fissile Material (kg/MWeyr)	In Storage	--	--	--	--	--	--
		In Transit	--	--	--	--	--	--

Table B-3: Footnotes

a-e. See notes a-e in Table A-3.

f. From ref. 4: 40 men per 500 ton/hour fluidized bed plant
8.1 injuries/million worker hours
death rate = 5% injury rate
and mid-point values of coal boiler with scrubber, Table A-3.

g. SOx only. See Table A-3, note f.

h. Table A-3, note g.

i. Table A-3, note h.

j. Table A-3, note i.

k. Table A-3, note j.

l. Table A-3, note l

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Table C-1: Coal with Low-Btu Gasification and Combined-Cycle Combustion

COSTS and RESOURCE UTILIZATION			HARVESTING FUELS (a)	UPGRADING FUELS (a)	TRANSPORTING FUELS (a)	CONVERSION TO ELECTRICITY (b)	MANAGEMENT OF FINAL WASTE (c)	TOTAL
COSTS	Power Plant Capital ($/kWe)					(d) 4.09 +2		
	Power Plant O&M ($/MWe/yr)					(e) 9.86 +3		
	Fuel (mills/kWHe)		1.07 1	5.27 -1	3.75 0	(f) 1.50 +1		
	Electricity (mills/kWHe)					(f) 3.09 +1		
	Fuel Cycle Capital ($/kWe)		4.76 1	4.64 0	4.71 1		(g)	9.93 1
	Fuel Cycle O&M ($/MWe-yr)		3.43 +4	1.70 +3	1.21 +4			4.81 +4
LABOR MH/MWe-yr	CONSTRUCTION (h)	Engineering	7.16 0	(a)	2.60 0	3.96 +1	(i)	4.94 +1
		Field Super. & Adm.	7.01 0	(a)	2.68 0	2.70 +1	(i)	3.67 +1
		Field Unskilled manual	2.89 0	(a)	5.36 0	4.86 +1	(i)	5.69 +1
		Field Skilled manual	3.25 +1	(a)	1.59 +1	2.71 +2	(i)	3.19 +2
		TOTAL	4.96 +1	(a)	2.65 +1	3.86 +2	(i)	4.48 +2
	O&M		1.62 +3	7.36 +1	9.21 +1	(j) 4.07 +2	(i)	2.19 +3
ENERGY	Primary	(MWth-yr/MWe-yr)	2.85 0	2.85 0	2.95 0	2.71 0	--	2.85 0
		Fuel Efficiency	1.00 0	9.64 -1	9.85 -1	3.70 -1	--	3.51 -1
	Ancillary	(MWth-yr/MWe-yr)	2.13 -2	6.52 -3	3.50 -2	(k) 3.52 -2	--	9.80 -2
MATERIALS MT/MWe-yr	CONSTRUCTION (h) METALS	Structural	4.93 -1	(a)	2.89 -2	3.26 -1	(i)	8.48 -1
		Pipes	1.64 -1	(a)	0	2.07 -1	(i)	3.71 -1
		Major Equipment	6.57 -1	(a)	8.67 -1	1.35 -1	(i)	1.66 0
		Other Equipment	0	(a)	5.78 -2	1.23 -1	(i)	1.81 -1
		TOTAL	1.31 0	(a)	9.54 -1	7.91 -1	(i)	3.06 0
	CONSTRUCTION (h)	Concrete	0	(a)	0	3.03 0	(i)	3.03 0
	O&M		--	--	--	(l) 7.88 0	--	7.88 0
LAND m²/MWe-yr	Temporarily Committed	TOTAL	4.5 +3	3.36 +1	3.49 +2	(m) 1.08 +2	(m) 2.70 +1	5.00 +3
		Undisturbed	0.5-3.0 +3	0	2.33 +2	0	0	0.8-3.2 +3
		Disturbed	1.5-3.9 +3	3.36 +1	1.16	1.08 +2	2.70 +1	1.8-4.2 +3
	Permanently Committed		0	0	0	0	0	0
WATER	(10^6 Liters/MWe-yr)		0	3.80 -1	0	8.81 0	(n) 0	9.19 0

Net: 3.39 -1

Table C-1: Footnotes

a. With an assumed overall power plant efficiency of 37% and an assumed capacity factor of 75%, the coal fuel cycle stages for the coal-C.C. system are precisely the same as those for the coal scrub system given in Table A-1.

b. The conversion step for this system includes a Lurgi type fixed-bed gasifier which provides low-Btu gas which is then input to a combined-cycle power system. The gasifier is assumed to have a 79% thermal efficiency and the combined cycle a 47% thermal efficiency (Ref. 103a), for an overall coal-electricity thermal efficiency of 37%. The capacity factor is assumed to be 75% and the plant life, 30 years.

c. Includes disposal of ash only, as the recovered sulfur is considered to be sold.

d. The capital cost for the Lurgi gasifier is taken from Reference (26) as \$170/Kwe in early 1974 dollars including interest during construction. This is considerably higher than other estimates we have seen (e.g., in References (1), (8), (99), and (101), but not inconsistent with that given in Reference (5)), but is thought to reflect the considerable scale-up and interfacing problems likely to be encountered in trying to interface a gasifier with a combined cycle power system. A report by the Fluor Corporation (being prepared for EPRI to help evaluate the choice between air and oxygen as a gasifying agent for utility application and due for publication during June of 1975) should yield more up-to-date estimates on both capital and conventional O & M costs for a Lurgi gasifier of the type required for this type of application. The original description of the Lurgi combined-cycle system may be found in Ref. (111) and those interested in the applicability of Lurgi gasification to other than non-caking coals are referred to Ref. (113). The gasifier cost of \$175/Kw was adjusted to mid-

1974 dollars by multiplying by 1.14 to reflect the early 1974 increase in the industrial wholesale price inde., (see e.g. Ref. (41)) yielding \$194/Kwe. A combined-cycle power system capital cost of \$174/Kwe was derived from Ref. (8) and adjusted to mid-1974 dollars by multiplying by 1.14 reflecting the increase in the Hardy-Whitman Steam Electric Construction index (Ref. (38)) during early 1974. To the \$198/Kwe estimate so obtained, was added 1.5 years of interest during construction at 10.5% as well as 6% inflation. The net interest rate is 4.25%, which gave a combined-cycle system cost of \$211/kWe. Therefore, the total coal C-C power plant capital cost was taken as \$409/kWe.

e. A conventional O & M cost of \$9.86 x 10^3/Mwe/yr is assumed to reflect the elimination of sludge disposal problems inherent in the coal-scrub and fluidized-bed systems considered in Tables A-1 and B-1, respectively. Although less dolomite is required for this coal based system than for the other two and although elemental sulfur may be sold for about \$10/ton, the O & M cost here is not reduced below 75% of that for the other two systems because of additional O & M costs necessary to run the gasifier.

f. The electricity cost equation, (A-1), given in note g of Table A-1 applies in the present case with:

$IT = 4.09 \times 10^8$ (from the first row of this table)

$G = .839$ (from note g., Table A-1)

$N = 9.86 \times 10^6$ (from the second row of this table)

$$EC = \underset{\text{capital}}{6.91} + \underset{\text{O \& M}}{9.00} + \underset{\text{fuel}}{15.0} = 30.91 \text{ mills/KwHe}$$

g. Capital and O & M costs for ash disposal are included in the corresponding power plant entries.

h. Power plant construction labor and materials data was derived from Ref. (8) and are annualized over the appropriate facility lifetime.

i. Waste disposal construction manpower and materials (which are quite small anyway) are included in the corresponding power plant entries.

j. O & M labor requirements at the power plant are taken as approximately equal to those for the coal-scrub system.

k. Ancillary energy requirements at the power plant are from Ref. (1). It is irrelevant whether or not some or all of this ancillary energy requirement may be actually satisfied internally by using the combined cycle output energy because of the uncertainty of our assumed plant efficiency.

l. Dolomite required for sulfur cleanup of the low-Btu gas is from Ref. (3).

m. Power plant land use is assumed equal to that for the coal-scrub system (although Ref. (1) gives only 14.4 m^2/Mwe-yr, facilities for coal storage and unit train unloading are still required as well as a buffer zone, which leads us to believe the power plant land requirement (excepting waste disposal requirements) for the two systems would be quite similar).

It is again assumed here that the power plant land requirement is all disturbed (but not permanently) although in reality part of it is probably a buffer zone.

For waste disposal, however, the coal C-C. system uses only one-fourth (Ref. (1)) as much land as the coal-scrub system, as there is no sludge disposal problem.

n. Water requirements at the power plant were derived from Ref. (3).

Table C-2: Coal with Low-BTU Gasification and Combined-Cycle Combustion

Environmental Releases			HARVESTING FUELS (a)	UPGRADING FUELS (d)	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY (g)	MANAGEMENT OF FINAL WASTE (j)	TOTAL
AIR	Non-Radioactive (metric tons/MWe-yr)	NO_x	4.0 -2	1.1 -1	1.9-2.8 -1	0.63-1.4 0	0	9.7-18.3 -1
		SO_x	2.9 -3	7.6 -2	1.7-2.5 -1	0.32-3.8 0	0	5.7-41.3 -1
		Particulates	1.4 -3	0.8-3.0 0	(f) 2.1-34.0 0	(k) 0.29-3.8 0	?	3.2-40.8 0
		HC	4.6 -3	0	1.6-2.3 -1	0 (l)	0	1.6-2.3 -1
		Toxic Metals	0	0	0	0.3-2.0 -2	?	0.3-2.0 -2
		Other	2.4 -2	0	2.7-4.8 -1	2.9-17.0 -1	?	5.8-24.2 -1
		Total	7.3 -2	1.0-3.2 0	2.9-35.2 0	1.5-10.7 0	?	5.5-49.2 0
	Radioactive (curies/MWeyr)	Rn	--	--	--	--	--	--
		H-3	--	--	--	--	--	--
		Kr-85	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Other	--	--	--	0.6-27.0 -5	--	0.6-27.0 -5
		Total	--	--	--	0.6-27.0 -5	--	0.6-27.0 -5
WATER	Non-Radioactive (MT/MWeyr)	Silt	8.9 -2	(e) 0.4-116.0 0	0	0	?	0.5-116.1 0
		Other	(b) 0.6-50.0 +1	(e) 0-7.2 0	0	(h) 2.2 -1	?	6.2-507.8 0
		Total	0.6-50.0 +1	0.4-123.2 0	0	2.2 -1	?	6.7-623.4 0
	Radioactive (curies/MWeyr)	H-3	--		--	--	--	--
		Trans U	--	--	--	--	--	--
		Other	--	--	--	--	--	--
		Total	--	--	--	--	--	--
SOLID	Non-Radioactive	(MT/MWe-yr)	(c) 1.3-1.8 +2	3.2-6.2 +2	0	(i) 3.0-3.8 +2	?	8.9-13.7 +2
	Radioactive (curies/MWeyr)	High Level (liters/MWeyr)	--	--	--	--	--	--
		Fission Prod.	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Total	--	--	--	--	--	--
		Low Level (liters/MWeyr)	--	--	--	--	--	--
		Intermediate (liters/MWeyr)	--	--	--	--	--	--
		Buried Solid (m^3/MWeyr)	--	--	--	--	--	--
		Tailings (curies/MWeyr)	--	--	--	--	--	--
THERMAL DISCHARGE (MWth-yr/MWe-yr)			0	0	0	1.7 0	0	1.7 0

Table C-2: Footnotes

a-f. See notes a-f, Table A-2.

g. Coal characteristics:

2.5 - 3.0% sulfur
10 - 12% ash
11,600 - 12,500 Btu/lb.

Power plant characteristics: (100-110, 113a)
98 - 99.7% sulfur removal
99 - 99.9% particulate removal by weight
37% thermal efficiency = 79% gasifier efficiency x 47% combined-cycle combustion efficiency.
0 - 67% of the coal is physically cleaned to remove 40% of the sulfur.
HC: High end from ref. 4 and low end from ref. 1.
Toxic metals and radioactive emissions assumed to be controlled to the same extent as particulates.
NOx: High end from ref. 15 (10% of natural gas emission rate which, from ref. 86 is 0.4 lb/million Btu) and low end from ref. 1.
The potential thermal efficiency is much higher. See chapters II and III and ref. 23, 28, 103.
An additional 0.3 MT/Mwe-yr of dissolved solids in cooling water drift could be added.

h. Based on new source performance standards (1).

i. From gasifier only (1)..

j. There would be some impact of handling the ash and sulfur produced in the gasifier.

k. See note q in Table A-2. Approximately 0.2 MT/MWe-yr.

l. See Reference 1.

Table C-3: Coal with Low-BTU Gasification and Combined-Cycle Combustion

Health Effects			HARVESTING FUELS (a)	UPGRADING FUELS (l)	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTAL
OCCUPA-TIONAL (per MWeyr)	Accidental	Death	0.8-2.2 -3	2.1-3.5 -5	1.6-5.0 -3	(f) 1.3 -4	(i) ?	2.6-7.4 -3
		Injury	0.4-1.1 -1	1.4-2.7 -3	1.3-4.8 -2	3.9 -3	?	5.8-16.5 -2
		Prs-days lost	0.7-2.0 +1	2.0-3.5 -1	(d) 1.0-3.5 +1	9.8 -1	?	1.8-5.7 +1
	Disease	Death	(b) 0-5.9 -5	0	0	0	0	0-5.9 -5
		Disability	5.5-8.2 -4	0	0	0	0	5.5-8.2 -4
		Prs-Days	0.3-4.0 -1	0	0	0	0	0.3-4.0 -1
PUBLIC (per MWeyr)	Accidental	Death	0	0	(e) 7.3 -4	0	0	7.3 -4
		Injury	0	0	1.6 -3	0	0	1.6 -3
		Prs-days	0	0	4.5 0	0	0	4.5 0
	Disease	Death	0	0	0	(g) .05-36.0 -4	(j) 0-1.3 -2	0.05-16.6 -3
		Disability	0	0	0	0.03-21.6 0	?	.03-21.6 0
		Prs-days	0	0	0	0.02-13.5 +1	?	.02-13.5 +1
LARGE ACCIDENTS	Maximum Size	Death	10-10^2	0	?	(h) ?	0	--
		Disability	?	0	?	?	0	--
	Societal Risk	Death	(c) 10^{-6}	0	?	?	0	?
		Disability	?	0	?	?	0	?
GENETIC RISK	TOTAL (k) (prs-rem Equiv./MWeyr)		?	?	?	?	?	?
SOCIAL EFFECTS	Fissile Material (kg/MWeyr)	In Storage	--	--	--	--	--	--
		In Transit	--	--	--	--	--	--

Table C-3: Footnotes.

a-e. See notes a-e in Table A-3.

f. Combined-cycle combustion (1), Lurgi gasification (4).

g. SOx only. See Table A-3, note f.

h-k. See Table A-3, notes g-j.

l. See Table A-3, note l.

Table D-1: Residual Fuel Oil

COSTS and RESOURCE UTILIZATION			HARVESTING FUELS a	UPGRADING FUELS b	TRANSPORTING FUELS c	CONVERSION TO ELECTRICITY d	MANAGEMENT OF FINAL WASTE e	TOTAL	
COSTS		Power Plant Capital ($/kwe)				f 2.80 +2			
COSTS		Power Plant O&M ($/Mwe/yr)				g 3.94 +3			
COSTS		Fuel (mills/kWHe) h	?	?	?	3.32 +1	j		
COSTS		Electricity (mills/kWHe) h				4.32 +1			
COSTS		Fuel Cycle Capital ($/kWe)	i 7.12 +1	i 5.74 +1	i 8.51 +0		j	1.37 +2	
COSTS		Fuel Cycle O&M ($/MWe-yr) k	1.10 +4	1.99 +4	5.50 +3		j	3.64 +4	
LABOR MH/MWe-yr	CONSTRUCTION i	Engineering	1.04 +1	4.64 0	4.33 -1	2.78 +1	0	4.33 +1	
LABOR MH/MWe-yr	CONSTRUCTION i	Field Super. & Adm.	5.36 0	5.01 0	2.00 -1	2.77 +1	0	3.83 +1	
LABOR MH/MWe-yr	CONSTRUCTION i	Field Unskilled manual	1.73 +1	6.14 0	1.35 0	2.79 +1	0	5.27 +1	
LABOR MH/MWe-yr	CONSTRUCTION i	Field Skilled manual	7.29 +1	3.97 +1	1.41 0	1.67 +2	0	2.81 +2	
LABOR MH/MWe-yr	CONSTRUCTION i	TOTAL	1.06 +2	5.55 +1	3.39 0	2.50 +2	0	4.15 +2	
LABOR MH/MWe-yr	O&M l		2.45 +2	2.04 +2	5.23 +1	2.26 +2	0	7.27 +2	
ENERGY m	Primary	(Mwth-yr/MWe-yr)	2.81 0	2.81 0	2.63 0	2.63 0	--	2.81 0	Net
ENERGY m	Primary	Fuel Efficiency	1.00 0	9.37 -1	1.00 0	3.80 -1	--	3.56 -1	3.35 -1
ENERGY m	Ancillary	(Mwth-yr/MWe-yr)	2.28 -2	1.43 -1	9.80 -3	0	--	1.76 -1	
MATERIALS MT/MWe-yr	CONSTRUCTION i METALS	Structural	5.46 -1	2.92 -2	1.91 -2	5.81 -2	0	1.18 0	
MATERIALS MT/MWe-yr	CONSTRUCTION i METALS	Pipes	5.45 -1	9.72 -2	1.84 -1	9.30 -2	0	9.19 -1	
MATERIALS MT/MWe-yr	CONSTRUCTION i METALS	Major Equipment	5.78 -2	2.40 -1	6.55 -3	5.56 -1	0	8.60 -1	
MATERIALS MT/MWe-yr	CONSTRUCTION i METALS	Other Equipment	4.12 -2	9.72 -3	5.92 -3	2.09 -1	0	2.66 -1	
MATERIALS MT/MWe-yr	CONSTRUCTION i METALS	TOTAL	1.19 0	3.76 -1	2.16 -1	1.44 0	0	2.98 0	
MATERIALS MT/MWe-yr	CONSTRUCTION i	Concrete	2.63 -1	4.23 -1	8.84 -3	2.42 0	0	3.11 0	
MATERIALS MT/MWe-yr	O&M		--	--	--	--	--	---	
LAND n m²/MWe-yr	Temporarily Committed	TOTAL	1.12 +3	1.18 +2	4.06 +2	4.50 +1	2.70 0	1.67 +3	
LAND n m²/MWe-yr	Temporarily Committed	Undisturbed	7.37 +2	7.55 +1	2.72 +2	o 0	0	1.08 +3	
LAND n m²/MWe-yr	Temporarily Committed	Disturbed	3.89 +2	4.25 +1	1.36 +2	4.50 +1	2.70 0	6.15 +2	
LAND n m²/MWe-yr	Permanently Committed		0	0	0	0	0	0 0	
WATER p	(10^6 Liters/MWe-yr)		0	1.95 0	0	1.36 +1	0	1.56 +1	

Table D-1: Footnotes

a. For the base case, the harvesting fuels stage consists of offshore oil extraction and transport of the crude to a refinery by pipeline. An alternative case of imported middle eastern crude was also considered and resources required for the tankers and import facilities necessary to transport this imported crude to a refinery are included in the appropriate footnotes below. The offshore facilities were assumed to have a twenty year lifetime, while the tanker and related facilities were assumed to last for thirty years.

b. For the RFO system the upgrading fuels stage corresponds to the operation of a petroleum refinery. This refinery was treated as if its entire output were residual fuel oil and resource utilizations scaled accordingly. For example, if the production of 1 barrel of petroleum products at a refinery consumes 1 liter of water, 1 barrel of RFO is also assumed to require this amount of water. See individual resource utilization category footnotes below for exceptions to this general rule. The refinery was assumed to have a thirty year lifetime.

c. All RFO is assumed to be transported by pipeline from the refinery to the power plant. The pipeline was assumed to have a thirty year life.

d. Quantities given are for an uncontrolled oil-fired power plant burning low sulfur residual fuel oil and with a natural draft evaporative cooling tower. The power plant was assumed to have a thermal efficiency of 38%, a capacity factor of 75% and a lifetime of 30 years.

e. For this system the management of final wastes consists only of the very small commitment of land required for disposal of the ash generated by RFO combustion.

f. The direct plus indirect capital cost (excluding interest during construction) for the RFO system was taken from Ref. (21) as $248/Kwe. Adding interest during construction of 3 years at the net interest of 4.25% gives a total capital cost of $280/kWe.

g. Conventional O & M costs were taken from Ref. (21) and other sources are 0.6 mills/KwHe, which for a plant at a 75% capacity factor translates to \$3940/Mwe/yr

h. The price of RFO was taken from Ref. (32) as 204.6¢/MBtu in December of 1974 and deflated by the consumer's price index to 193 ¢/MBtu in mid-1974. dollars. For the present case the electricity cost equation (A-1) in note g of Table A-1 needs only slight modification to reflect the slightly higher thermal efficiency assumed here. Making this adjustment, equation (A-1) becomes:

$$EC = \underbrace{1.69 \times 10^{-8} \times IT}_{\text{Capital Cost}} + \underbrace{2.97 \times 10^{-7} \times (.051T + N)}_{\text{O \& M cost}} + \underbrace{17.2G}_{\text{Fuel Cost}}$$

Now, for the RFO system:

$IT = 2.80 \times 10^{8}$ (from first row of table)

$G = 1.93$ (from first sentence of this footnote)

$N = 3.94 \times 10^{6}$ (from second row of table)

$$\therefore EC = \underset{\text{Capital}}{4.73} + \underset{\text{O \& M}}{5.33} + \underset{\text{Fuel}}{33.20} = 43.25 \text{ mills/KwHe}$$

Therefore the total contribution of the cost of fuel to the cost of electricity for the RFO system is large -- 33.20 mills/KwHe on a national average basis. No breakdown of the contribution of the various stages of the fuel cycle to the cost of RFO delivered to the power plant was attempted, partly due to the difficulty of assigning cost contributions to refinery products and partly due to lack of good data.

i. Fuel cycle facility capital costs, construction labor requirements and construction materials requirements are derived from data given in Ref. (8). Fuel cycle capital requirements are the investment required to build enough capacity for one Mwe-yr 's worth of fuel production capacity. This was done because of the diverse required rates of return and accounting procedures utilized in the various fuel cycle industries. Construction manpower and materials requirements are, however, annualized by dividing the requirements to construct capacity sufficient to provide one Mwe-yr. of fuel by the assumed (see notes a-e) facility lifetimes. For the imported middle eastern crude case the requirements for tankers and oil import facilities would be: Fuel cycle capital cost = $.. .6 \times 10^4$/Mwe-yr; Engineering = 3.95 MH/Mwe-yr; Field Super. and Adm.= 1.39 MH/Mwe-yr; Field Unskilled Manual = 4.07 MH/Mwe-yr; Field Skilled Manual = 1.78×10^1 MH Mwe-yr; Total construction labor = 2.72×10^1 MH/Mwe-yr; Structural = 3.74×10^{-1}MT/Mwe-yr; Pipe = 3.39×10^{-1} MT/Mwe-yr; Major Equipment 7.69×10^{-2} MT/Mwe-yr; Minor Equipment = 1.6? x 10^{-2} MT/Mwe-yr; Total Construction Metals = 8.06 MT/Mwe-yr and Concrete = 8.71×10^{-3} MT/Mwe-yr.

j. Very small capital and O & M costs for ash and sludge disposal are included in the corresponding power plant entries.

k. Fuel cycle O & M costs were derived from References (1) and (118); supertanker O & M costs were not obtained.

l. O & M labor requirements were derived from data in References (118), (120), and (1). O & M labor for supertanker transport was derived from Ref. (121) as 2.07×10^2 MH/Mwe-yr.

m. Thermal efficiencies and ancillary energy requirements were obtained from References (1), (118) and (120). Ancillary electrical requirements were again backfigured to primary fuel requirements as per note j of Table A-1 An ancillary energy requirement of 1.12×10^{-1} Mwth-yr/Mwe-yr for supertankers was derived from data given in Ref. (1).

n. Land requirements were derived from data given in References (1), (2), (3), (4), (7), and (8) and are annualized over the assumed facility lifetimes, (e.g., a fixed commitment of land necessary for enough refinery capacity for one Mwe-yr. is divided by the assumed refinery lifetime to get the land use consumption per Mwe-yr.) The surface area of offshore drilling platforms was considered as land use, but this amounts to a disturbed temporary commitment of only 2×10^1 m^2/Mwe-yr. Pipelines (both crude and RFO carrying) are assumed to average 300-360 miles in length and to require right of way of 62.5 feet, only 1/3 of which is assumed to be disturbed (by access roads and other maintenance and operating facilities). None of the land commitments for the RFO system are assumed to be permanent, at least not in the same sense as for nuclear system facilities. Land use for a tank farm for import facilities is small at 1.84 m^2/Mwe-yr (from Ref (1)).

o. Although some of the temporary land use for the RFO power plant is probably used as a buffer zone and hence not disturbed, to be conservative, we have chosen to treat the entire power plant land commitment as being disturbed.

p. Water consumption data is primarily from references (3) and (7) and refers only to evaporated water which for the RFO system is only required for cooling at the refinery and power plant.

Table D-2: Residual Fuel Oil

Environmental Releases			HARVESTING FUELS (a)	UPGRADING FUELS (c)	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY (f)	MANAGEMENT OF FINAL WASTE	TOTAL
AIR	Non-Radioactive (metric tons/MWe-yr)	NO_x	3.5-4.1 -1	0.4-1.7 0	3.5-4.1 -1	5.5-11.2 0	0	6.6-13.7 0
		SO_x	0.3-6.2 -1	0.1-1.8 0	0.3-6.2 -1	2.3-38.5 0	0	2.5-41.5 0
		Particulates	1.5-7.7 -2	0.8-2.3 -1	1.5-7.7 -2	(m) 0.2-2.2 0	0	3.1-25.8 -1
		HC	1.2-4.8 -2	2.3 0	1.2-4.8 -2	0.7-1.5 0	0	3.0-3.9 0
		Toxic Metals	0	0	0	(g) 0.2-2.0 -1	(j) ?	0.2-2.0 -1
		Other	0.8-250.0 -3	1.4 -2	0.8-250.0 -3	(h) 0.7-10.0 0	0	0.7-10.5 0
		Total	0.4-1.4 0	2.9-6.0 0	4.1-14.1 -1	9.4-63.6 0	?	13.1-72.3 0
	Radioactive (curies/MWeyr)	Rn	--	--	--	--	--	--
		H-3	--	--	--	--	--	--
		Kr-85	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Other	--	--	--	(i) 5.2-5.5 -7	--	5.2-5.5 -7
		Total	--	--	--	5.2-5.5 -7	--	5.2-5.5 -7
WATER	Non-Radioactive (MT/MWeyr)	Silt	0	5.8-14.0 -2	0	0	(k) ?	5.8-14.0 -2
		Other	(b) 2.7-7.9 -1	(d) 2.8-6.8 0	(e) 1.1-7.2 -1	7.3-27.0 -2	?	3.3-8.6 0
		Total	2.7-7.9 -1	2.9-6.9 0	1.1-7.2 -1	7.3-27.0 -2	?	3.4-8.7 0
	Radioactive (curies/MWeyr)	H-3	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Other	--	--	--	--	--	--
		Total	--	--	--	--	--	--
SOLID	Non-Radioactive	(MT/MWe-yr)	0	0	0	1.9-7.8 0	(l) ?	1.9-7.8
	Radioactive (curies/MWeyr)	High Level (liters/MWeyr)	--	--	--	--	--	--
		Fission Prod.	--	--	--	--	--	--
		Trans U	--	--	--	--	--	--
		Total	--	--	--	--	--	--
		Low Level (liters/MWeyr)	--	--	--	--	--	--
		Intermediate (liters/MWeyr)	--	--	--	--	--	--
		Buried Solid (m^3/MWeyr)	--	--	--	--	--	--
		Tailings (curies/MWeyr)	--	--	--	--	--	--
THERMAL DISCHARGE (MWth-yr/MWe-yr)			0	2.7 -1	0	1.63 0	0	1.9 0

Table D-2: Footnotes

a. Offshore domestic production plus pipeline. Most of the impacts are from the pipeline.

The following emissions are associated with foreign production plus crude transport by tanker:

Air: NO_x 0.028 MT/MWe-yr   Water: 0.64 MT oil spillage/MWe-yr
SO_x 0.044
Part 0.0032
HC 0.0019
Other 0.0003

We have not made a distinction between the impacts of outer continental shelf production and near off-shore production or between tanker transport and super-tanker transport.

b. Oil spillage. About 5.8 $(10)^3$ MT brine could be added to this impact. See note e and ref. 114-119.

c. Refinery emissions are assumed to apply on a Btu basis to RFO which comprises about 6% of an average U.S. refinery's output (1, 3, 7, 11a)

d. Includes 3.0 - 7.1 $(10)^{-3}$ MT oil.

e. Oil spillage rates: 0.006%(1) - 0.04%(3).

f. RFO characteristics:

0.6 - 1.0% sulfur by weight
6.3 $(10)^6$ Btu/bbl

Plant characteristics:

0 - 90% removal of sulfur
90 - 99% removal of particulates

The range of NO_x is due to the best new boilers available today on the high end and down by a factor of two to account for future combustion modifications at the low end (15). An additional 0.3 dissolved solids in drift from cooling towers could be added.

g. See ref. 5 & 81.

h. High number from ref. 7, low number from ref. 3.

i. Two thirds Ra-228, one-third Ra-226. (3, 80, 209-214)

j-l. See Table A-2, notes k-m.
See refs. 84-86.

m. See footnote q in Table A-2.

Table D-3: Residual Fuel Oil

Health Effects			HARVESTING FUELS (a)	UPGRADING FUELS (d)	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTAL
OCCUPATIONAL (per MWeyr)	Accidental	Death	3.3 -6	3.7-5.6 -5	5.5-7.1 -5	1.3-5.0 -5	0	1.1-1.8 -4
		Injury	2.6 -4	3.1-4.0 -3	0.3-6.3 -3	1.5-4.8 -3	0	5.2-15.4 -3
		Prs-days lost	(b) 2.8 -2	3.8-5.4 -1	(e) 3.4-6.2 -1	2.0-6.8 -1	0	9.5-18.7 -1
	Disease	Death	0	0	0	0	0	0
		Disability	0	0	0	0	0	0
		Prs-Days	0	0	0	0	0	0
PUBLIC (per MWeyr)	Accidental	Death	0	0	0	0	0	0
		Injury	0	0	0	0	0	0
		Prs-days	0	0	0	0	0	0
	Disease	Death	0	0	0	(f) .04-36.5 -3	0	.04-36.5 -3
		Disability	0	0	0	0.02-21.8 +1	0	.02-21.8 +1
		Prs-days	0	0	0	0.02-13.7 +2	0	.02-13.7 +2
LARGE ACCIDENTS	Maximum Size	Death	(c) 10^2-10^3	(g) 10^2-10^3	(c) 10^2-10^3	(g) 10^2-10^3	0	--
		Disability	?	?	?	?	0	--
	Societal Risk	Death	?	(g) 2.7 -7	?	(g) 2.7 -7	0	?
		Disability	?	?	?	?	0	?
GENETIC RISK	TOTAL (prs-rem Equiv./MWeyr) (h)		?	?	?	?	?	?
SOCIAL EFFECTS	Fissile Material (kg/MWeyr)	In Storage	--	--	--	--	--	--
		In Transit	--	--	--	--	--	--

Table D-3: Footnotes.

a. Offshore + pipeline.

The rates for foreign production + tanker import are: (1, 4, 7)

Deaths $8.0(10)^{-5}$ /MWe-yr

Injuries $6.5(10)^{-3}$ /MWe-yr

Person-days lost 0.8/MWe-yr

We have not made a distinction between the accident rates of outer continental shelf production and near off-shore production or between tanker transport and supertanker transport.

b. 31 days/injury (1).

c. Tanker explosions (115-118, 205).

d. See Table D-2, note c.

e. 31 days/injury (1).

f. SOx only. See Table A-3, note f and also ref. 101.

g. From SOx released in a large fire at a refinery or at a storage tank farm for a power plant. (191).

h. See Table A-3, note j.

Table E-1: Light-Water Reactor

COSTS and RESOURCE UTILIZATION			HARVESTING FUELS (a)	UPGRADING FUELS (b)	TRANSPORTING FUELS (c)	CONVERSION TO ELECTRICITY (d)	MANAGEMENT OF FINAL WASTE (e)	TOTAL
COSTS (f)	Power Plant Capital ($/kWe)					(g) 4.24 +2		
	Power Plant O&M ($/MWe/yr)					(h) 5.26 +3		
	Fuel (mills/kWhe) (i)		(l) 3.64 0	3.22 0	0	7.70 0	8.40 -1	
	Electricity (mills/kWhe) (i)					2.27 +1		
	Fuel Cycle Capital ($/kWe) (j)		2.74 0	3.09 +1	0		5.35 0	(p) 3.90 +1
	Fuel Cycle O&M ($/MWe-yr)		?	(k) 6.90 +3	0		?	?
LABOR MH/MWe-yr	CONSTRUCTION (j)	Engineering	5.64 -1	2.15 0	0	6.53 +1	1.04 0	6.91 +1
		Field Super. & Adm.	3.35 -1	8.15 -1	0	9.62 +1	8.66 -1	9.82 +1
		Field Unskilled manual	3.56 -1	3.19 0	0	8.59 +1	1.45 0	9.09 +1
		Field Skilled manual	1.63 0	1.22 +1	0	3.57 +2	4.61 0	3.75 +2
		TOTAL	2.89 0	1.84 +1	0	6.04 +2	7.97 0	6.33 +2
	O&M (l)		1.15 +2	9.01 +1	0	2.50 +2	3.12 +1	4.86 +2
ENERGY	Primary (m)	(Mwth-yr/MWe-yr)	4.67 +2	4.44 +2	3.13 0	3.13 0	(m)	4.67 +2
		Uranium Eff.	9.50 -1	7.04 -3	1.00 0	3.20 -1	(m)	2.14 -3 Net (o) 3.07 -1
	Ancillary	(Mwth-yr/MWeyr) (m)	4.01 -3	1.26 -1	1.73 -5	0	1.56 -4	1.30 -1
MATERIALS MT/MWe-yr	CONSTRUCTION (j) METALS	Structural	2.51 -3	3.65 -2	0	1.25 0	8.32 -4	1.29 0
		Pipes	0	1.43 -2	0	1.23 -1	1.10 -3	1.38 -1
		Major Equipment	3.05 -3	2.90 -2	0	2.46 -1	6.04 -3	5.17 -1
		Other Equipment	0	7.71 -2	0	2.26 -1	2.75 -4	3.03 -1
		TOTAL	5.58 -3	3.90 -1	0	1.85 0	8.25 -3	2.25 0
		Concrete	1.83 -2	3.15 -1	0	1.24 +1	6.59 -3	1.27 +1
	O&M		--	--	--	--	--	--
LAND (n) m²/MWe-yr	Temporarily Committed	TOTAL	2.55 +2	1.17 +1	0	4.82 +1	1.20 +1	3.27 +2
		Undisturbed	1.75 [illegible]	1.03 +1	0	4.16 +1	1.14 +1	2.38 +2
		Disturbed	7.97 +1	1.35 0	0	6.30 0	6.16 -1	8.90 +1
	Permanently Committed		2.34 +1	9.18 -2	0	6.30 0	1.06 0	3.09 +1
WATER (n)	(10^6 Liters/MWe-yr)		2.78 -1	3.81 -1	0	2.30 +1	1.56 -2	2.37 +1

Table E-1: Footnotes

a. Includes mining and milling of U_3O_8 (yellowcake). A 20 year lifetime is assumed for these facilities. Surface mining was assumed for the base case, but national average data are given for fuel cost and operational manpower Data, where available, for uranium deep mines is given in the appropriate footnotes.

b. Includes conversion of U_3O_8 to UF_6, enrichment of UF_6 and fuel element fabrication. A 30 year life is assumed for these facilities.

c. Costs and resource utilization for transport of nuclear fuels is included in the appropriate fuel cycle step totals, e.g., about 1/12 of the cost of management of final wastes may be attributed to the cost of spent-fuel shipping.

d. This column represents costs and resource utilizations for a Light-Water Reactor (LWR) with a natural draft evaporative cooling tower, a thermal efficiency of 32% and a capacity factor of 75%.

e. This stage includes spent fuel shipping and reprocessing, as well as management of final wastes.

f. Because of their many steps and time lags the nuclear fuel cycles are inherently more difficult to analyze than the fossil fuel cycles. In the present analysis fuel cycle charges are discounted as they occur. Basically the electricity cost equation used for the fossil system (equation A-1, note g, Table A-1), must be modified as follows: Equation E-1

$$EC = \underbrace{1.69 \times 10^{-8} \times IT}_{\text{Capital Cost}} + \underbrace{2.97 \times 10^{-7} (.05\ IT + N)}_{\text{O \& M Cost}} + \underbrace{1.69 \times 10^{-8} \times PV(FC)}_{\text{Fuel Cost}}$$

where IT & N = as before the plant capital cost and O & M cost in mid-1974 dollars and PV(FC) = the present value of the fuel cycle charges over the lifetime of the plant discounted to the date of commercial operation. Since 6% long-term inflation and 10.5% interest are assumed, the net discount rate is 4.25% (1.105/1.06) and this is used to determine the present value of the nuclear fuel cost steam. This approach is taken since nuclear fuel costs are a string of capital charges rather than a fuel cost in \$/MBTU is with fossil fuels. The contributions of the costs of the various fuel cycles operating to the cost of the initial core are included in the fuel cost rather than the capital cost. This is conventional and makes it easier to consider unequal fuel and capital escalation rates in the sensitivity analyses of Chapter 3.

g. A capital cost of \$371/kWe, excluding interest during construction and escalation, was obtained from Reference (21). To this was added interest during construction for 3.75 years at 10.5% interest and 6% long-term inflation. The net interest is 4.25%, for a total capital cost of \$424/kWe.

h. The power plant O & M costs was taken from Ref. (21) as $\$5.26 \times 10^3$/Mwe/yr.

i. The value of the initial core was calculated using fuel cycle requirements and timing obtained from Ref. (11). The model mass balance represents 2/3rds of a PWR and 1/3 of a BWR. This corresponds to the ratio at which capacity of these two types of reactors will be built according to References (11) and (231). The fuel cycle requirements for the initial core are assumed to be 442 MT of U_3O_8, 554 MT of UF_6 Conversion, 203 MT of separative work and 87 MTU of fuel fabrication. What the unit costs by the various fuel cycle services will be between now and the end of the century (to say nothing of beyond this point) is an extremely controversial subject: the question of U_3O_8 availability being perhaps the most controversial issue. (c.f. References (45), (159 - 162), (172)) We would be foolhardy to base our entire analysis on a single plausible U_3O_8 availability-nuclear capacity buildup scenario, and so the sensitivity of nuclear power generation costs to U_3O_8 price is included in Chapter 3. For the base case, however, we have chosen the case D scenario in Ref. (11) to represent the buildup of nuclear generating capacity. We assume a 0.25% tails assay and do not discount the capacity buildup by 20% due to recent cancellations and delays as was done in Reference (145), because we want this LWR option to be one in which Plutonium is not recycled. See Table F-1 for the Pu recycle case. We chose to believe that the differences between forward cost and selling price* for U_3O_8 given in Ref. (176), (and alluded to in Reference (161)), will materialize and further that all the estimated additional reserves tabulated in this Reference will be discovered on a timely basis between now and the end of the century and that the U_3O_8 price will stay relatively fixed over the first 19 years of the next century due to new discoveries or breeders. This seems completely reasonable as References (145), (159) and (232) suggest that substantial additional discoveries may be possible in the long run). Combining the U_3O_8 availability and price data of Reference (176) with the nuclear generating capacity data in Ref. (11) we arrived at a mid-1974 dollars price of \$13/lb. U_3O_8 in 1988 (which is when the U_3O_8 for the initial core would have to be purchased in order to have a commercial LWR by our 1990 reference date). Other fuel cycle charges necessary to compute the initial core value were gathered from References (11), (145), (231), and (6) and were assumed to be as follows: Conversion to UF_6 at \$150/lb.-U, Enrichment at \$75/SWU, and Fuel Fabrication at \$70/KgU. Using also the fuel cycle load times given in Ref. (11) and a 4.25% net or real rate of interest (the fuel-cycle inventory holding

*Forward cost is used here as marginal cost of extracting U_3O_8 from existing mines based on government economies, i.e., no profit, no capital charges, etc. Selling price is U_3O_8 cost from future mines based on industrial economics.

charges are thus treated exactly the same as interest during construction), an initial core value of 37.5 million dollars was calculated. Further, the final core at the end of the assumed 30 year plant life has a discounted value of 18.6 million dollars.

Using the same U_3O_8 availability and nuclear capacity buildup scenarios as above, we used a \$14/lb.-U_3O_8 price for the first 5 years of the reference reactor's operation, \$27/lb.-U_3O_8 for the second 5 years of operation and \$45/lb.-U_3O_8 for the final 20 years of reactor life. To the fuel cycle charges given above is added a \$120/kgU reprocessing and waste management charge. The reactor was assumed to move from the initial core configuration to its steady state configuration as quickly as possible (i.e., as soon as reprocessed fuel is available it is assumed to be recycled at the steady-state level). For this case no Pu recycle was considered and therefore the output Pu from the reactor was assumed to have no value. The rationale behind this assumption was that if breeders are deemed safe, so will Pu recycle, and then either an LWR Pu recycle economy or an LWR-Breeder economy will emerge in the short run. See Chapter 3 for a discussion of the costs and resource utilizations for these multiple-reactor-systems. The steady state reload mass balance used was again derived from References (3), (7), and (11), and assumed a 0.15% tails assay, for a 2/3rds Pwr-1/3 BWR model reactor. This means that 154 MT of U_3O_8, 193 MT of UF_6 conversion, 102 MT of separative work, 27.5 MTU of fuel fabrication and 26 MTU of fuel reprocessing are required each year. The present value of the fuel-cycle charges was then calculated as 456 million dollars (including the initial core and credit for the final core).

Next, using the following input data:

$$IT = 4.24 \times 10^{8} \quad \text{(from line 1 of Table)}$$
$$N = 5.26 \times 10^{6} \quad \text{(from line 2 of Table)}$$
$$PV(FC) = 4.56 \times 10^{8} \quad \text{(from above)}$$

we can use equation E-1 of note f to calculate the electricity generation cost as follows:

$$EC = \underset{\text{Capital}}{7.17} + \underset{\text{O \& M}}{7.86} + \underset{\text{Fuel}}{7.70} = 22.73\ \frac{\text{mills}}{\text{KwHe}}$$

with the breakdown of the contributions of the costs of various stages of the fuel cycle to the fuel cost as shown in the Table.

j. Fuel-cycle capital costs (not annualized, i.e., spread over the assumed facility lifetime) and construction manpower and materials requirements (annualized over the assumed facility lifetimes) are primarily from reference (8). For a more disaggregated breakdown of these requirements see the reference cited in note k of Table A-1 as well as references (146), (147), (168), and (231). For capital costs for various waste disposal alternati... see reference (20).

The capital cost for underground uranium mining would be $\$4.31 \times 10^{3}$/Mwe-yr. Manpower required for such mining would include 1.08 MH/Mwe-yr of engineers, 6.9×10^{-1} MH/Mwe-yr of field supervision and administrative personnel, 6.3×00^{-1} MH/Mwe-yr of field unskilled manual labor and 3.3 MH/Mwe-yr of field skilled manual labor, for a total construction manpower requirement of 5.70 MH/Mwe-yr. Materials required for underground uranium mining would include 3.25×10^{-2} MT/Mwe-yr of structure metals and 8.45×10^{-3} MT/Mwe-yr of metals for major equipment for a total metals requirement of 4.10^{-2} MT/Mwe-yr of metals, as well as 5.18×10^{-2} MT/Mwe-yr of concrete.

k. From references (21) and (231).

l. From references (7) and (231).

m. Based on an energy potential of 22,000 Kwht/gram U for complete fissioning of U. The "efficiency" of the upgrading fuels stage actually includes the whole fuel cycle including reprocessing. For this system a small amount of fission potential is lost by discarding Pu and a great deal is left in the enrichment tails both from reload and recycle operations. Actually if a breeder economy emerges these tails can be used as the fertile material in the breeders. LWRs, however, use natural uranium quite inefficiently.

n. From references (2), (3), (6), (7), (9) and (12). Land used for current reactor sites ranges from 84-30,000 acres, with an average commitment of 1160 acres (ref. (148)), but much of this land is purchased to accomodate future expansions in generating capacity. The 250 acres per site figure used here is from ref. (2) and should be viewed only as a representative figure.

o. Net efficiency for nuclear plants is primary energy efficiency at the generating plant corrected for total ancillary energy use assuming ancillary energy could by converted to electricity at the primary efficiency at the conversion plant. For example, net efficiency = 1/(3.13 + 0.13) = 0.307.

p. The total capital charge can be found by adding the plant and fuel capital charges. $(\$/kWe)_{Total} = 424 + 0.75 \times 39 = 453 \$/kWe$.

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Table E-2: LWR

Environmental Releases			HARVESTING FUELS *	UPGRADING FUELS	TRANSPORTING FUELS (e)	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTA:
AIR	Non-Radioactive (metric tons/MWe-yr)	NO_x	1.5 - 2.6 -2	1.0 - 2.2 -2	0	0	7.4 - 8.9 -3	3.2 - 5.7 -2
		SO_x	5.7 -2	1.8 - 5.0 -2	0	0	7.8 -3	8.3 - 11.5 -2
		Particulates	1.2 -2	0	0	(l) 0	2.0 -3	1.4 -2
		HC	2.0 -3	2.5 -4	0	0	2.5 -5	2.3 -3
		Toxic Metals	0	0	0	0	0	0
		Other (a)	4.0 -4	1.5 -2	0	0	1.9 -4	1.6 -2
		Total	8.6 - 9.7 -2	4.3 - 8.7 -2	0	0	1.2 - 1.9 -2	1.4 - 2.0 -1
	Radioactive (curies/MWeyr)	Rn	1.5 - 9.0 -2	0	0	--	0	1.5 - 9.0 -2
		H-3	--	--	0	(f) 0 - 5.0 -2	(i) 2.4-23.0 0	2.4 - 23.0 0
		Kr-85	--	--	0	(f) 0.8-73.0 -1	(h) 1.7-480.00	1.3 - 490.00
		Trans U	--	--	0	0	3.7-13.0 -5	3.7 - 13.0 -5
		Other	(b) 8.4 - 8.8 -5	2.9 - 14.0 -5	0	0.8-100.0 -2	1.4-680.0 -4	0.8-106.8 -2
		Total	1.5 - 9.0 -2	2.9 - 14.0 -5	0	0.9-83.5 -1	3.7-[illegible]0.0 0	3.8-510.0 0
WATER	Non-Radioactive (MT/MWe-yr)	Silt	0	0	0	0	0	0
		Other (c)	2.7 -43.0 +1	4.5 -11.0 -2	0	7.3-110.0 2	5.9 -8.5 -3	2.7-43.0 +1
		Total	2.7 -43.0 +	4.5 -11.0 -2	0	7.3-110.0 -2	5.9 -8.5 -3	2.7 -43.0 +1
	Radioactive (curies/MWeyr)	H-3	--	0	0	(f) 0 -45.0 -2	(i) 0 -3.3 0	0 - 3.3 0
		Trans U	--	0	0	5.0 -3	0	5.0 -3
		Other	2.5 - 5.9 -3	1.2 - 3.6 -4	0	0	1.9-37.0 -4	2.8 -100 -3
		Total	2.5 - 5.9 -3	1.2 - 3.6 -4	0	0.5-77.0 -2	0.2-3300.0 -3	7.8-4100.0 -3
SOLID	Non-Radioactive	(MT/MWe-yr)	(d) 8.5 - 11.4 +4	3.8 - 8.3 -3	0	0	0	8.5-11.4 +4
	[illegible]active (curies/MWeyr)	High Level (liters/MWeyr)	--	--	--	--	4.3 -4.8 +1	4.3-4.8 +1
		Fission Prod.	--	--	--	--	1.3 - 5.3 +5	1.3 - 5.3 +5
		Trans U	--	--	--	--	(j) 2.1 +1	2.1 +1
		Total	--	--	--	--	1.3 - 5.3 +5	1.3 - 5.3 +5
		Low Level (liters/MWeyr)	--	--	--	0	1.3 +3	1.3 +3
		Intermediate (liters/MWeyr)	--	--	--	0	2.6 +1	2.6 +1
		Buried Solid (m^3/MWeyr)	--	2.6 - 14.0 -4	--	8.3 -4	(j) 2.0 -1	2.0 -1
		Tailings (curies/MWeyr)	(b) 1.1 - 1.5 -1	(k) 6.2 -2	--	(i) 4.2 +1	--	1.1 - 1.5 -1
THERMAL DISCHARGE (MWth-yr/MWe-yr)			2.7 -3	3.8 -2	0	2.13 0	2.0 -3	2.17 0

* 50% underground + 50% surface mining.

Table E-2: Footnotes

a. Mostly CO, some HF^- is emitted in the upgrading steps.

b. Mostly Th and U.

c. The category of "other" also includes nonradioactive water impacts whose character was not specified.

d. Includes 2.5 - 3.4 $(10)^3$ MT overburden from surface mining. See refs. 157-158.

e. Transport inpacts are very small and are included within the other steps.

f. The high end of these ranges represents a PWR without advanced controls. A BWR emits 0.016 H^3 and 50 Ci Kr. The low end represents the containment of 99% of H^3 and Kr + Xe and is the more likely at the end of this century. (165, 166)

g. Curies in low level waste from power plant.

h. Lower end represents containment of noble gas radionuclides and H^3. See note f. (43).

i. Plutonium.

j. Includes 4.3 $(10)^3$ Ci of cladding hulls. If noble gas is contained approximately 6 $(10)^{-3}$ gas cylinders are needed as well.

k. Ci of depleted uranium tails stored as UF_6 at the enrichment plant. Chemical toxicity would be the greater hazard here.

l. An additional 0.5 MT/Mwe-yr of dissolved solids from cooling tower drift could be added. (See refs. 50, 142, 186, 191, 193, 209, 214).

Table E-3: LWR

Health Effects			HARVESTING FUELS	UPGRADING FUELS (f)	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTAL
OCCUPATIONAL (per MWeyr)	Accidental	Death	(d) 1.2-2.7 -4	6.7 -6	2.7-12.0 -6	1.3-1.7 -5	2.0 -7	1.4-3.1 -4
		Injury	3.2-13.0 -3	2.0 -3	6.0-12.0 -5	1.7 -3	1.2 -4	7.1-16.9 -3
		Prs-days lost	8.8-23.0 -1	1.4 -1	1.9-7.8 -2	1.6-1.9 -1	4.9 -3	1.2-2.7 0
	Disease (a)	Death	(e) 3.4-6.0 -6	2.0 -6	(g) 0.3-40.0 -7	(i) 3.0-11.0 -5	7.4 (m) -5	1.1-2.0 -4
		Disability	0.7-1.2 -5	4.0 -6	0.6-80.0 -7	6.0-22.0 -5	1.5 -4	2.2-3.9 -4
		Prs-Days	2.1-3.7 -2	1.2 -2	0.2-24.8 -3	1.8-6.7 -1	4.6 -1	6.8-12.0 -1
PUBLIC (per MWeyr)	Accidental	Death	?	0	1.2 -5	0	0	1.2 -5
		Injury	?	0	1.1 -4	0	0	1.1 -4
		Prs-days	?	0	8.0 -2	0	0	8.0 -2
	Disease (a)	Death	?	?	2.2 -7	3.3-130.0 -7	(l) 8.0-19.0 -7	1.4-15.1 -6
		Disability	?	?	4.4 -7	6.6-260.0 -7	1.6-3.8 -6	2.8-30.2 -6
		Prs-days	?	?	1.4 -3	2.0-80.6 -3	4.9-12.0 -3	0.3-93.6 -3
LARGE ACCIDENTS	Maximum Size	Death	$10-10^2$	?	(h) $10^{-1}-10$	(k) 10^3-10^5	?	--
		Disability	?	?	?	10^4-10^7	?	--
	Societal Risk	Death	?	?	(h) $10^{-7}-10^{-12}$	(k) $10^{-2}-10^{-7}$	?	?
		Disability	?	?	?	$10^{-1}-10^{-6}$	?	?
GENETIC RISK	TOTAL (b) (prs-rem Equiv./MWeyr)		1.527 -2	2.0-? -2	2.5-42.2 -3	4.0-12.0 -1	4.0-24.0 -2	4.7 - ? -1
SOCIAL EFFECTS	Fissile Material (c) (kg/MWeyr)	In Storage	--	--	0	0.32	0.04	0.21
		In Transit	--	--	(j) 0.2	--	0.21	0.21

Table E-3: Footnotes

a. The risk of cancer is taken to be 2.0 $(10)^{-4}$ cases/person-rem for whole body exposure. Except for mining and accidents no attempt has been made to evaluate other than whole body routine exposures. See ref. 186 and 188 for a discussion of other exposures. In this study one half of the cancers are assumed to be fatal, except for thyroid nodules which are taken as 1% fatal. (22, 188, 190).

b. The total genetic risk to succeeding generations is thought to be roughly equal to the somatic risk for the parent generation. However, there is a large uncertainty in the estimate of this risk. (22). A Working Level Month (WLM) exposure to uranium miners is taken to be 0.1 rem for genetic calculations.

c. Fuel cycle in ref. 11.

d. The lower end represents the approximate accident rate for surface mining and the higher end represents underground mining.

e. These numbers represent 50% underground and 50% surface mining. One WLM is taken to be equal to 5 rem to the lung and the risk of lung cancer is taken to be 1.6 $(10)^{-5}$ cases/rem. (This assumes a 25 year plateau period of cancer induction and is taken from ref. 22). About 55 underground miner-years per year would be required to supply 100% of the uranium for a 1000-Mwe pi at 75% capacity. Each miner, therefore, has about 3.0 $(10)^{-4}$ chances of lung cancer per year. This would be considered only an order of magnitude estimate. (Ref. 5 , for example, determined the risk to be about 5.2 $(10)^{-4}$ (4 WLM/miner-year) and indicated that the risk might be several times higher or lower.) (10, 139, 190)

f. Average of BWR and PWR: mill and upgrade.

g. Low end from ref. 18 and high end from ref. 7.

h. (85 miles/Mwe-yr) x (2.0 - 800.0 $(10)^{-11}$ large accidents/mile) x (10.0 - 1000.0 prs-rem/accident) x (0.0001 deaths/prs-rem), Reference 18.

i. Material in transit from reprocessing plant to sale or storage.

j. High end from ref. 187.

k. Loss of Coolant Accident (LOCA) and no Emergency Core Cooling leading to core melt and loss of containment during the worst weather conditions. For the studies dealing with severities only, we have applied the probabilities in Wash-1400 (17). There are also uncertainties in the probabilities but we have not included in this table. If included the range indicated here would extend this range considerably. Estimates of the maximum individual risk range from seven (17) to three (200) orders of magnitude lower than the societal risk. (6, 14, 17, 191, 192, 195-205) Does not include sabotage.

l. Reprocessing only (9). See also Table H-3, note j. No risk included from long-term storage or disposal of nuclear wastes do to lack of information on these effects.

m. Reprocessing only - 31 day/injury (Ref. 7).

Table F-1: Light-Water Reactor with Plutonium Recycle.

COSTS and RESOURCE UTILIZATION			HARVESTING FUELS ⓐ	UPGRADING FUELS ⓑ	TRANSPORTING FUELS ⓒ	CONVERSION TO ELECTRICITY ⓔ	MANAGEMENT OF FINAL WASTE ⓓ	TOTAL	
COSTS	Power Plant Capital ($/kWe)					ⓔ 4.24 +2			
COSTS	Power Plant O&M ($/Mwe/yr)					ⓔ 5.26 +3			
COSTS	Fuel (mills/kWHe) ⓔ		2.38 0	2.97 0	0	6.28 0	9.30 -1		
COSTS	Electricity (mills/kWHe)					ⓔ 2.13 +1			
COSTS	Fuel Cycle Capital ($/kWe) ⓕ		2.27 0	2.31 -1	0		5.88 0	3.12 +1	
COSTS	Fuel Cycle O&M ($/MWe-yr)		?	ⓖ 5.24 +3	0		?	?	
LABOR MH/MWe-yr	CONSTRUCTION ⓕ	Engineering	4.68 -1	3.35 0	0	6.53 +1	1.14 0	7.03 +1	
LABOR MH/MWe-yr	CONSTRUCTION ⓕ	Field Super. & Adm.	2.78 -1	7.08 -1	0	9.62 +1	9.52 -1	9.81 +1	
LABOR MH/MWe-yr	CONSTRUCTION ⓕ	Field Unskilled manual	2.95 -1	2.66 0	0	8.59 +1	1.59 0	9.04 +1	
LABOR MH/MWe-yr	CONSTRUCTION ⓕ	Field Skilled manual	1.35 0	1.05 +1	0	.57 +2	5.07 0	3.73 +2	
LABOR MH/MWe-yr	CONSTRUCTION ⓕ	TOTAL	2.39 0	1.72 +1	0	6.04 +2	8.76 0	6.32 +2	
LABOR MH/MWe-yr	O&M ⓖ		9.55 +1	8.38 +1	0	2.50 +2	3.43 +1	4.63 +2	
ENERGY ⓗ	Primary ⓚ	(Mwth-yr/MWeyr)	3.88 +2	3.69 +2	3.13 0	3.13 0	ⓚ	3.88 +2	Net
ENERGY ⓗ		Fuel efficiency	9.50 -1	8.49 -3	1.00 0	3.20 -1	ⓚ	2.58 -3	3.07 -1
ENERGY ⓗ	Ancillary	(Mwth-yr/MWeyr)	3.33 -3	9.17 -2	1.73 -5	0	1.72 -4	9.52 -2	
MATERIALS MT/MWe-yr	CONSTRUCTION ⓕ METALS	Structural	2.08 -3	2.97 -2	0	1.25 0	9.15 -4	1.28 0	
MATERIALS MT/MWe-yr	CONSTRUCTION ⓕ METALS	Pipes	0	1.20 -2	0	1.23 -1	1.21 -3	1.36 -1	
MATERIALS MT/MWe-yr	CONSTRUCTION ⓕ METALS	Major Equipment	2.53 -3	2.51 -2	0	2.46 -1	6.64 -3	2.80 -1	
MATERIALS MT/MWe-yr	CONSTRUCTION ⓕ METALS	Other Equipment	0	7.63 -3	0	2.26 -1	3.02 -4	2.34 -1	
MATERIALS MT/MWe-yr	CONSTRUCTION ⓕ METALS	TOTAL	4.63 -3	7.45 -2	0	1.85 0	9.08 -3	1.94 0	
MATERIALS MT/MWe-yr	CONSTRUCTION ⓕ	Concrete	1.52 -2	2.54 -1	0	1.24 +1	7.25 -3	1.26 +1	
MATERIALS MT/MWe-yr	O&M		--	--	--	--	--	--	
LAND ⓘ m²/MWe-yr	Temporarily Committed	TOTAL	2.12 +2	8.70 0	0	4.82 +1	1.20 +1	2.81 +2	
LAND ⓘ m²/MWe-yr	Temporarily Committed	Undisturbed	1.45 +2	7.63 0	0	4.16 +1	1.14 +1	2.05 +2	
LAND ⓘ m²/MWe-yr	Temporarily Committed	Disturbed	6.62 +1	1.02 0	0	6.30 0	6.16 -1	7.42 +1	
LAND ⓘ m²/MWe-yr	Permanently Committed		1.94 +1	7.62 -2	0	6.30 0	1.06 0	2.68 +1	
WATER ⓙ	(10^6 Liters/MWe-yr)		2.31 -1	3.04 -1	0	2.30 +1	1.72 -2	2.35 +1	

Table F-1: Footnotes

a. For the Pu-recycle option, 83% of the U_3O_8 requirement for a non Pu-recycle LWR is required. The numbers here are therefore 83% of those in the corresponding column of Table E-1. The Pu recycle option considered here is the often called the self generating reactor (SGR) option in that the LWR is assumed to burn up only the Pu it produces. Option in which several LWR's are used to produce Pu for use in a single LWR therefore operate in excess of the SGR Pu requirement. As pointed out in Ref. (12) though, LWR's operating in excess of about 1.15 SGR would require substantial design modifications.

b. For an LWR-Pu 83% of the conversion requirement, 79% of the enrichment requirement and 67% of the uranium fabrication requirement of an LWR is necessary. The resource utilizations for these activities can then be simply scaled from data developed for Table E-1. The remaining 1/3 of the fuel load requires mixed oxide (MOx) fabrication in which material uranium is blended with recycled plutonium.

c. Remarks made in notes c & d of Table E-1 apply here as well.

d. As we assume safeguards at a level consistent with plutonium disposition case IV of Ref. (11) the cost and resource utilizations for reprocessing and waste management are assumed to be 30% higher than for the LWR case. However since only 1/3 of the spent fuel is MOx, costs and resource utilization per electrical megawatt year increase by only 10%.

e. The initial core in the present case was assumed to be the same as in the LWR case and from Ref. (3), (7), and (11) the steady-state reload requirement for a SGR. LWR-Pu with a 75% capacity factor and a 0.25% tails assay were assumed to be: 128 MT of U_3O_8, 161 MT of UF_6 conversion, 81 MT of separative work, 18.5 MTU of uranium fuel element fabrication, 9.0 MTH* of MOx fabrication and 26.0 MTH of spent fuel reprocessing. It was assumed that since Pu is recycled here not only is less U_3O_8 required per reactor-year, but also cumulative U_3O_8 requirements were assumed to be 20% less than in the LWR (Table E-1) case. Using the methods for estimating U_3O_8 prices given in note i of Table E-1, we derived for the present case a U_3O_8 price of \$13/lb. for the initial core and first five years of reactor operation, \$22/lb. for the 2nd five years of reactor operation, and \$36/lb. for the last 20 years of operation. The cost of MOx fabrication was assumed to be twice that of uranium fuel fabrication (i.e. \$140/KgH) and the cost of reprocessing MOx fuel was assumed to be 30% or greater than the cost of reprocessing uranium fuel. Using these additional requirements and charges the present value of fuel charges over the life of the reactor (including initial core cost and final core credit) was calculated as 371 million dollars. Consequently, using;

$IT = 4.24 \times 10^8$ (from first row of Table)

$N = 5.26 \times 10^6$ (from second row of Table)

$PV(FC) = 3.71 \times 10^8$ (from above)

We get an electric generation cost of:

$$EC = \underset{\text{capital}}{7.17} + \underset{\text{O \& M}}{7.86} + \underset{\text{Fuel}}{6.28} = 2\text{[illegible]}.31 \ \frac{\text{mills}}{\text{KwHe}}$$

with the breakdown of the contributions of the costs of the various stages of the fuel cycle to the fuel cost as shown in the Table.

f. Data on fuel cycle capital costs, as well as construction, labor, and materials requirements including MOx fuel fabrication and reprocessing facilities was obtained primarily from references (8) and (231).

* Metric ton of heavy metal (MTH).

g. From Ref. (231).

h. From References (2), (3), (9), and (12).

i. Primarily from References (2), (3), (9) and (12). Plutonium disposition option IV from Ref. (12) where the MOx facilities are assumed to be contiguous with the reprocessing facilities, so that no new land is committed for the purpose of fabricating MOx fuels. This measure is proposed for safeguards reasons, however, not primarily as a land saving measure.

j. Primarily from References (3), (7), (9), and (12).

k. See note m, Table E-1.

Table I-2: LWR with PU Recycle

Environmental Releases			HARVESTING FUELS	UPGRADING FUELS (e)	TRANSPORTING FUELS (h)	CONVERSION TO ELECTRICITY (i)	MANAGEMENT OF FINAL WASTE (l)	TOTAL
AIR	Non-Radioactive (metric tons/MWeyr)	NO_x	1.3 - 2.2 -2	1.4 -2	0	0	7.4-8.9 -3	3.4 - 4.5 -2
		SO_x	4.7 -2	3.1 -2	0	0	7.8 -3	1.1 -1
		Particulates	1.0 -3	0	0	(p) 0	2.0 -3	3.0 -3
		HC	1.7 -3	2.3 -4	0	0	2.5 -5	2.0 -3
		Toxic Metals	0	0	0	0	0	0
		Other (a)	3.3 -4	1.4 -2	0	0	(m) 1.9 -4	1.5 -2
		Total	6.3-7.2 -2	5.9 -2	0	0	1.7-1.9 -2	1.4-1.8 -1
	Radioactive (curies/Mweyr)	Rn	1.3 - 7.5 -2	0	0	--	0	1.3 - 7.5 -2
		H-3	--	0	0	(j) 0 - 5.0 -2	(m) 2.4-23.0 0	2.4 -23.1 0
		Kr-85	--	0	0	(j) 0.8-73.0 -1	(m) 1.3-480.00	0.1 -48.7 +1
		Trans U	--	(f) 2.4 -8	0	0	3.7-13.0-5	3.7 -13.0 -5
		Other	7.0 - 7.3 -5	3.9 -6	0	0.8-100.0-2	1.5-680.0-4	0.8-106.8 -2
		Total	(h) 1.3 - 7.5 -2	3.9 -6	0	0.9-84.0 -1	0.4-50.0 +1	0.4-50.8 +1
WATER	Non-Radioactive (MT/MWeyr)	Silt	0	1.5 -1	0	0	0	1.5 -1
		Other (c)	2.2 -35.7 +1	6.5 -2	0	7.3-110.0-2	5.9- 8.5 -3	2.2-35.8 +1
		Total	2.2 -35.7 +1	2.2 -1	0	7.3-110.0-2	5.9- 8.5 -3	2.2-35.8 +1
	Radioactive (curies/MWeyr)	H-3	--	--	0	(j) 0 - 45.0 -2	(m) 0 - 3.3 0	0 -3.8 0
		Trans U	--	8.2 -7	0	5.0 -3	0 0	5.0 -3
		Other	h 2.5 - 5.9 -3	1.2 -4	0	0	1.9 -37.0-4	2.8- 9.7 -3
		Total	2.5 - 5.9 -3	1.2 -4	0	0.5-45.5-2	2.2-3300.0-3	0.8-38.1 -1
SOLID	Non-Radioactive	(MT/MWe-yr)	(d) 8.5 -11.4 +4	3.8 -8.3 +3	0	0	0	8.9-12.2 +4
	Radioactive (curies/MWeyr)	High Level (liters/MWeyr)	--	--	--	--	4.3 -4.8 +1	4.3-4.8 +1
		Fission Prod.	--	--	--	--	1.3 -5.3 +5	1.3 - 5.3 +5
		Trans U	--	?	--	--	(n) 1.1 +3	1.1 +3
		Total	--	--	--	--	1.3 - 5.3 +5	1.3 - 5.3 +5
		Low Level (liters/MWeyr)	--	--	--	0	1.3 +3	1.3 +3
		Intermediate (liters/MWeyr)	--	--	--	0	2.6 +1	2.6 +1
		Buried Solid (m^3/MWeyr)	--	2.6-14.0 -4	--	8.3 -4	(o) 2.0 -1	2.0 -1
		Tailings (curies/MWeyr)	(b) 1.1-1.5 -1	(g) 3.9 -2	--	(k) 4.2 +1	--	1.1 - 1.5 -1
THERMAL DISCHARGE (MWth-yr/MWe-yr)			2.2 -3	3.2 -2	0	2.13 0	2 -3	2.16 0

Table F-2: Footnotes

a-d. See Table E-3, notes a-d.

e. 70% of LWR UF_6 enrichment and UO_2 fabrication emissions plus MOx fabrication emissions (12). Here taken as 90% of mean LWR value. See Table E-2.

f. Alpha radiation -- twice as much if beta radiation is included.

g. See E-2, note k.

h. See E-2, note e.

i. No significant differences from LWR plants.

j. See E-2, note f.

k. See E-2, note g.

l. No significant difference in emissions compared to LWR except for Trans-U in final waste.

m-o. See E-2, notes h-j.

p. See footnote 1 Table E-2

Table F-3: LWR with Pu Recycle

Health Effects			HARVESTING FUELS (d)	UPGRADING FUELS (g)	TRANSPORTING FUELS (h)	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTAL
OCCUPA-TIONAL (per MWeyr)	Accidental	Death	(e) 1.0-2.2 -4	6.7 -6	2.7-12.0-6	1.3-1.7 -5	2.0 -7	1.2-2.6 -4
		Injury	2.7-10.8-3	2.0 -3	6.0-12.0-5	1.7 -3	1.2 -4	6.6-14.7 -3
		Prs-days lost	7.3-19.1-1	1.4 -1	1.9-7.8 -2	1.6-1.9 -1	4.9 -3	1.1-2.3 0
	Disease (a)	Death	(f) 2.8-5.0 -6	2.8 -7	0.3-40.0 -7	2.4 -5	(m) 1.9 -6	2.4-3.5 -5
		Disability	5.8-9.9 -6	5.6 -7	0.6-80.0 -7	4.8 -5	2.8 -6	5.8-6.2 -5
		Prs-Days	1.7-3.1 -2	1.7 -3	0.2-24.8 -3	1.5 -1	1.2 -2	1.8-3.2 -1
PUBLIC (per MWeyr)	Accidental	Death	?	0	1.2 -5	0	0	1.2 -5
		Injury	?	0	1.1 -4	0	0	1.1 -4
		Prs-days	?	0	8.0 -2	0	0	8.0 -2
	Disease (a)	Death	?	?	2.2 -7	3.3-130.0-7	(l) 8.0-19.0 -7	1.4-15.1 -6
		Disability	?	?	4.4 -7	6.6-260.0-7	1.6-3.8 -6	2.8-30.2 -6
		Prs-days	?	?	1.4 -3	2.0-80.6 -3	4.9-12.0 -3	0.8-9.4 -2
LARGE ACCIDENTS	Maximum Size	Death	$10-10^2$	?	(i) $10^{-1}-10$	(k) 10^3-10^5	?	--
		Disability	?	?	?	10^4-10^7	?	--
	Societal Risk	Death	?	?	(i) $10^{-7}-10^{-12}$	(k) $10^{-2}-10^{-7}$	?	?
		Disability	?	?	?	$10^{-1}-10^{-6}$	?	?
GENETIC RISK	TOTAL (b) (Pers-rem Equiv./MWeyr)		1.2-? -2	2.0 - ? -2	2.5-42.2 -3	4.0-12.0-1	1.3-? -1	5.6-? -1
SOCIAL EFFECTS	Fissile Material (c) (kg/MWeyr)	In Storage	--	0.05	0	0.55	0.05	0
		In Transit	--	0.27	(j) 0.76	--	0.27	0.27

Table F-3: Footnotes

a,b. See Table E-3, notes a and b.

c. Fuel cycle in ref. 12.

d. A LWR-Pu Recycle system requires about 83% as much uranium mining as a LWR without recycle. (12)

e,f. See Table E-3, notes d and e. See also ref. 163.

g. Under alternative 4 in reference 12, reprocessing and fabrication plants and the transport operations between them and the reactor would be subject to enhanced security arrangements. See also ref. 141, 164.

h. Same as LWR. Perhaps there would be slightly more impact because of shipments to and from MOx plants. (Ref. 12 indicates there could be up to 3 times the exposure of LWR system but it uses estimates at the low end of the LWR estimates.)

i. See Table E-3, note g.

j. See Table E-3, Note i.

k. See Table E-3, Note k.

l. Reprocessing only. See Table H-3, note j.

m. See Table E-3, note m.

Table G-1: Liquid Metal Fast Breeder Reactor

COSTS and RESOURCE UTILIZATION			HARVESTING FUELS (a)	UPGRADING FUELS (b)	TRANSPORTING FUELS (c)	CONVERSION TO ELECTRICITY (d)	MANAGEMENT OF FINAL WASTE (e)	TOTAL	Net
COSTS	Power Plant Capital ($/kWe)					(f) 5.50 +2			
	Power Plant O&M ($/Mwe/yr)					(g) 5.83 +3			
	Fuel (mills/kWHe) (h)		4.50 -2	1.54 0	0	2.48 0	8.90 -1		
	Electricity (mills/kWHe)					(i) 2.17 +1			
	Fuel Cycle Capital ($/kWe) (j)		2.06 -2	4.00 0	0		4.01 0	8.03 0	
	Fuel Cycle O&M ($/MWe-yr)		?	?	0		?	?	
LABOR MH/MWe-yr	CONSTRUCTION (j)	Engineering	4.23 -3	3.46 0	0	6.53 +1	7.80 -1	6.95 +1	
		Field Super. & Adm.	2.51 -3	1.37 -1	0	9.62 +1	6.49 -1	9.69 +1	
		Field Unskilled manual	2.67 -3	3.04 -1	0	8.59 +1	1.08 0	8.73 +1	
		Field Skilled manual	1.22 -2	1.87 0	0	3.57 +2	3.46 0	3.62 +2	
		TOTAL	2.16 -2	5.77 0	0	6.04 +2	5.97 0	6.15 +2	
	O&M (k)		8.63 -1	1.62 +1	0	2.50 +2	1.54 +1	2.82 +2	
ENERGY	Primary (m)	(MWth-yr/MWe-yr)	3.15 0	2.99 0	2.56 0	2.56 0	(m)	3.15 0	
		Fuel Efficiency	9.50 -1	8.60 -1	1.00 0	3.90 +1	(m)	3.17 -1	3.9 -1
	Ancillary	(MWth-yr/MWe-yr)	3.01 -5	1.44 -3	0	0	1.17 -4	1.59 -3	
MATERIALS MT/MWe-yr	CONSTRUCTION (j) METALS	Structural	1.88 -5	1.69 -3	0	1.25 0	6.24 -4	1.25 0	
		Pipes	0.00 0	1.69 -3	0	1.23 -1	8.25 -4	1.26 -1	
		Major Equipment	2.29 -5	5.08 -3	0	2.46 -1	4.53 -3	2.56 -1	
		Other Equipment	0	3.38 -3	0	2.26 -1	2.06 -4	2.29 -1	
		TOTAL	4.18 -5	1.18 -2	0	1.85 0	6.19 -3	1.86 0	
		Concrete	1.37 -4	1.18 -2	0	1.24 +1	4.94 -3	1.24 +1	
	O&M		--	--	--	--	--	--	
LAND m²/MWe-yr (l)	Temporarily Committed	TOTAL	1.91 0	2.42 0	0	4.82 +1	2.18 0	5.47 +1	
		Undisturbed	1.31 0	2.06 0	0	4.16 +1	2.06 0	4.70 +1	
		Disturbed	5.98 -1	3.63 -1	0	6.30 0	1.15 -1	7.38 0	
	Permanently Committed		1.76 -1	0	0	6.30 0	2.87 -1	6.71 0	
WATER	(10⁶ Liters /MWe-yr) (l)		2.09 -3	4.58 -3	0	1.78 +1	1.65 -2	1.78 +1	

Table G-1: Footnotes

a. Includes the mining and milling of a small amount of U_3O_8 for blending with Pu. The U_3O_8 requirement actually turns out to be 0.75% of that for an LWR and so the quantities given in this column are 0.75% of those given in the first column of Table E-1. In the early years of the Breeder much of the requirement for fertile material will be met by utilizing depleted uranium that has been stockpiled as enrichment tails in the preparation of enriched uranium fuel for LWRs. In a mature breeder economy, however, some U_3O_8 must be mined.

b. Includes the purchase of Pu for the initial core and the first two annual reloads, plus the sale of bred Pu he remainder of the reactor life, as well as fuel element fabrication facilities, which have an assumed lifetime of 30 years.

c. As for the other reactor concepts considered the transport of nuclear fuels from facility to facility costs very little and requires only a small commitment of non-fuel resources. Consequently, transport costs and resource utilizations are included in the totals given for other stages of the nuclear fuel cycle.

d. This column includes costs and resource utilizations associated with the operation of a model LMFBR with a 39% thermal efficiency, a capacity factor of 75% and a plant lifetime of 30 years.

e. This column includes fuel reprocessing and waste management. The reprocessing facilities are postulated to be very much like those used to reprocess LWR fuel and are assumed to have a thirty year lifetime.

f. Based on discussions in Refer s (6) it is assumed that the capital cost for the first LMFBRs will exceed that of an LWR by about $125/Kwe. See Reference (232) for a critique of this cost estimate.

g. Conventional O & M costs are based on a scale-up from LWR O & M in accordance with that given in Ref. (6).

h. The fuel resource requirements (both those for the initial core and for reloads) were taken from References (3), (6), and (11). The initial core was assumed to require 53 MT of U_3O_8, 2.31 MT of Pu and 47 MTH* of fabrication and 19.2 MTH of reprocessing with the first two reloads requiring an additional 1.61 MT of Pu and 20.6 MT of U_3O_8 because it was assumed (in accordance with fuel cycle timing data given in Ref. (11)) that recycled material could not be returned to the reactor until the second annual reload after discharge.

The U_3O_8 price scenario used was identical to that used for the LWR-Pu system (see Table F-1). The price of Pu was set equal to its value as a recycle fuel in LWRs (this being predicated on the assumption that during the early days of the Breeder it would have only a small impact on this established market value). Consequently the Pu price depends upon the prevailing U_3O_8 price (as well as the prevailing tails assay, the cost of separative work and the cost differential between MOx and uranium oxide fuel fabrication). It was basically assumed that 1 gram of Pu could be substituted for 0.8 grams of U-235 and therefore that 1 gram of Pu was "worth" 144 grams of U_3O_8 and 96 SWUs but that a cost penalty of about $1.50 is incurred by having to fabricate MOx LWR-Pu fuel as opposed to Uranium oxide fuel. This gives a Pu price of $10/gr for the first 5 years of reactor operation, $12.50/gr for the second five years of operation and $20/gr for the last 20 years of reactor operation. One would probably need an elaborate systems analysis model to adequately account for the effects of the rates of buildup of capacity of the different reactor types on the price of Pu.

* Metric ton of heavy metal (MTH)

As building and justifying such a model was clearly beyond the scope of this study, it is somewhat reassuring to note that although estimates of Pu price in our time frame range from negative (for the cost of disposing of a product already in abundant supply) to about \$40/g (where breeders are assumed to have a clear economic advantage even at a high Pu price and this effect is thus reinforcing as there exists an incentive to expand Breeder capacity as quickly as possible) most of those we have seen are in the \$10 to \$20 range.

Using this fuel cycle requirement and cost data the present value of fuel costs over the entire reactor life was calculated at 147 million dollars.

i. Collecting data from above as follows:

$IT = 5.50 \times 10^8$ (from first row of Table)

$N = 5.83 \times 10^6$ (from second row of Table)

$PV(FC) = 1.47 \times 10^8$

we may use equation (**) of note g, Table E-1 to calculate the cost of generating electricity using the LMFBR system as:

$$EC = \underset{\text{Capital}}{9.29} + \underset{\text{O \& M}}{9.90} + \underset{\text{Fuel}}{2.40} = 21.7 \text{ mills/KwHe}$$

j. Capital cost and construction manpower and materials requirements were obtained largely from Ref. (8). As phase I of the Bechtel study did not explicitly include the LMFBR several (possibly heroic) assumptions had to be made to obtain the data shown. First of all, the LMFBR power plant was assumed to require the same amounts of construction manpower and materials as an LWR. At the level of aggregation of our data this is clearly implied in Ref. (6). Even at a more disaggregated level, materials requirements for an LMFBR compared with those for a PWR are estimated to be quite similar (*e.g.* compare estimated composite and primary materials requirements given for an LMFBR in Section 5 of Ref. (6), with data given for the same materials in Ref. (168) Further, the fabrication facilities for LMFBR fuels are assumed to be similar to those used for MOx fabricating for the LWR-Pu system and reprocessing facilities are assumed to be similar to those used to reprocess LWR fuel. These assumptions are also used in Ref. (6).

k. Primarily from Ref. (6).

l. Primarily from References (3) and (6).

m. See note m, Table E-1.

Table G-2: LMFBR

Environmental Releases			HARVESTING FUELS (a)	UPGRADING FUELS	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTAL
AIR	Non-Padioactive (metric tons/MWe-yr)	NO_x	1.1-1.9 -4	0	0	0	5.8-6.3 -3	5.9-6.5 -3
		SO_x	4.2 -4	0	0	0	0	4.2 -4
		Particulates	8.9 -5	0	0	0 (f)	0	8.9 -5
		HC	1.5 -5	0	0	0	0	1.5 -5
		Toxic Metals	0	0	0	0	0	0
		Other	2.9 -6	(b) 0-3.8 -5	0	0	0-2.5 -4	0.29-29.0 -5
		Total	6.3-7.0 -4	0-3.8 -5	0	0	5.8 - 6.6 -3	5.4 - 7.3 -3
	Radioactive (curies/MWeyr)	Rn	1.1-6.6 -4	0	0	--	0	1.1-6.6 -4
		H-3	--	0	0	(i) 0-7.5 -2	2.4-25.1 0	2.4-25.2 0
		Kr-85 *	--	0	0	(g) 1.8-70.0 -1	(i) 0.9-2400.0 0	1.0-2407.0 0
		Trans U	--	(c) 0.6-160.0 -7	0	0	0.5-16.0 -6	0.55-320.0 -6
		Other	6.1-6.4 -7	0.3-16.0 -7	0	0-1.8 -3	0-4.0 -4	0.64-2202.0 -6
		Total	6.3-7.0 -4	0.9-166.0 -7	0	0.8-70.8 -1	3.3-2425.0 0	3.4-2432 0
WATER	Non-Radioactive (MT/MWe-yr)	Silt	0	0	0	0	0	0
		Other	0	0	0	2.1-33.0 -2	0	2.1-33.0 -2
		Total	2.0-31.0 -1	0	0	2.1-33.0 -2	0-4.2 -3	2.1-33.0 -2
	Radioactive (curies/MWeyr)	H-3	--	0	0	(i) 0-7.5 -2	0-2.4 0	0-2.4 0
		Trans U	--	(c) 0-?	0	0	0-? 0	0-?
		Other	1.8-4.3 -5	4.9-15.0 -6	0	0	0-2.6 -3	0.23-26.6 -4
		Total	1.8-4.3 -5	?	0	0-7.5 -2	0-?	1.8-? -5
SOLID	Non-Radioactive	(MT/MWe-yr)	0.6-83.0 +1	0	0	0	0	0.6-83.0 +1
	Radioactive (curies/MWeyr)	High Level (liters/MWeyr)	--	--	--	--	0.2-3.4 +1	0.2-3.4 +1
		Fission Prod.	--	--	--	--	5.4 +5	5.4-? +1
		Trans U	--	(d) 41.0-? 0	--	--	5.0-34.0 +1	91.0-? 0
		Total	--	?	--	--	5.4 +5	5.4-? +5
		Low Level (liters/MWeyr)	--	--	--	0	1.0 +3	1.0 +3
		Intermediate (liters/MWeyr)	--	--	--	0	2.0-7.9 +1	2.0-7.9 +1
		Buried Solid m^3/MWeyr)	--	3.5-11.0 -1	--	(h) 3.5-8.1 -2	(i) 7.0-3.6 -3	3.9-94.7 -1
		Tailings (curies/MWeyr)	0.8-11.0 -3	(e) 1.7 -5	--	--	--	0.8-11.0 -3
THERMAL DISCHARGE (Mwth-yr/MWe-yr)			1.7 -5	1.4 -4	0	1.56 0	8.0 -4	1.56 0

*Kr+Xe

Table G-2: Footnotes

a. The amount of uranium mining and milling required for the LMFBR cycle is about 0.75% of the requirement for the LWR cycle. See tables E-2 and footnotes.

b. HF-release

c. The total uncertainty is larger than indicated here. See Section III-B-2.

d. Plutonium in solid waste from fabrication plant. See note c.

e. Uranium in solid waste from fabrication plant.

f. About 0.3 MT/Mwe-yr of dissolved solids from cooling tower drift could be added here.

g. Low end is more probable. High end is uncontrolled release of Kr, Xe and H-3. (174)

h. 5.9 m^3 / Mwth-yr containing 4.8 Ci at EBR-II (175).

i. Includes cladding hulls. If Kr is contained, 6.3 $(10)^{-3}$ gas cylinders/ Mwe-yr are needed. See Refs. 170-175, 191.

Table G-3: LMFBR

Health Effects			HARVESTING FUELS (d)	UPGRADING FUELS	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTAL
OCCUPATIONAL (per MWeyr)	Accidental	Death	8.7-20.0 -7	4.4 -7	2.8-96.0 -6	1.8 -5	8.8 -8	2.2-11.6 -5
		Injury	2.3-9.5 -5	2.8 -4	0.8-10.0 -4	1.8 -3	8.2 -5	2.3-3.3 -3
		Prs-days lost	6.8-17.0 -3	1.9 -2	2.1-64.0 -2	1.9 -2	4.6 -3	7.0-70.0 -2
	Disease (a)	Death	1.1-5.0 -8	2.0 -6	3.6-15.0 -7	4.0 -5	3.2 -6	4.6-4.7 -5
		Disability	2.2-9.5 -8	4.0 -6	7.2-30.0 -7	8.0 -5	6.4 -6	9.2-9.4 -5
		Prs-Days	6.8-31.0 -5	1.2 -2	2.2-9.3 -3	2.5 -1	2.0 -2	2.8-2.9 -1
PUBLIC (per MWeyr)	Accidental	Death	?	0	1.3 -5	0	0	1.3 -5
		Injury	?	0	1.2 -4	0	0	1.2 -4
		Prs-days	?	0	8.4 -2	0	0	8.4 -2
	Disease (a)	Death	?	1.9 -9	3.6 -7	7.1-27.0 -8	(e) 5.5 -8	4.9-6.9 -7
		Disability	?	3.8 -9	7.2 -7	1.4-5.4 -7	1.1 -7	9.8-13.8 -7
		Prs-days	?	1.2 -5	2.2 -3	4.4-17.0 -4	3.4 -4	3.0-4.3 -3
LARGE ACCIDENTS	Maximum Size	Death	$10-10^{2}$	10^{-4} - ?	(e) 10^{-4}-?	(f) $10^{3}-10^{5}$	10^{-5}-?	--
		Disability	?	?	?	?	?	--
	Societal Risk	Death	?	?	(e) $10^{-11}-10^{-14}$	(f) $10^{-2}-10^{-8}$	?	?
		Disability	?	?	?	?	?	?
GENETIC RISK	TOTAL (b) (Prs.-rem Equiv./MWeyr)		[illegible]-5.0 -4	2.0-? -2	7.2-19.0 -3	4.0-? -1	3.2-? -2	4.6-? -1
SOCIAL EFFECTS	Fissile Material (c) (kg/MWeyr)	In Storage	--	0.4	0	2.9	0.4	0.2
		In Transit	--	2.1	(f) 4.5	--	2.1	2.1

Table G-3: Footnotes

a,b. See notes a and b of Table E-3.

c. Fuel cycle in reference 3.

d. 0.75% of the uranium requirement of the LWR cycle. See Table E-3, notes d and e.

e. From reference 6. See also Table E-3, note h.

f. See note j of Table E-3.

g. Although the mechanisms leading to accidents and the accident conditions might be very different in LMFBRs, the uncertainties in the analyses do not allow a distinction to be made between the probabilities of severe accidents in LMFBRs as compared to LWRs. In fact, reference 191 calculates the probability of failure leading to a significant release of radioisotopes to be 10^{-4} - 10^{-5}/reactor-year for a LMFBR which is close to the $6.0(10)^{-5}$ calculated in W-1400 (17) for a LWR. (6)

The severity of LMFBR accidents may also be quite different from LWRs. Basically there are very similar amounts of fission products in both systems and any difference in effects results from the much larger amount of plutonium and the existence of radioactive sodium in LMFBR (as well as the difference in release mechanisms, fuel rods containment systems, etc.). Reference 191 calculates that only 0.4 gram of plutonium could be released in the largest accident. Ref. 175 calculates that only 0.03 grams would be released. These amounts represent fractions of 10^{-7} to 10^{-8} of the total plutonium inventory and only a very small addition to the radiation doses caused by the fission product releases. Under these conditions, the severity of LMFBR accidents is similar to LWR accidents. (See Table E-3) However, there is some doubt about the validity of such small releases. Reference 191 calculates the total risk of LMFBRs as 10^{-6} to 10^{-8} deaths/Mwe-yr, similar to or smaller than the risk for LWRs in W-1400 (17). It should be emphasized that these estimates are subject to even more uncertainty than the LWR risk estimates. (6, 172-175) Does not include sabotage.

h. Reprocessing only (6). See also Table H-3, note j. No risk included from long-term storage or disposal of nuclear waste due to lack of information on these effects.

Table H-1: High Temperature Gas Cooled Reactor

COSTS and RESOURCE UTILIZATION			HARVESTING FUELS (a)	UPGRADING FUELS (b)	TRANSPORTING FUELS (c)	CONVERSION TO ELECTRICITY (d)	MANAGEMENT OF FINAL WASTE (e)	TOTAL
COSTS	Power Plant Capital ($/kWe)					(f) 4.40 +2		
COSTS	Power Plant O&M ($/Mwe/yr)					(g) 5.26 +3		
COSTS	Fuel (mills/kWHe) h		1.74 0	2.93 0	0 0	5.00 0	3.70 -1	
COSTS	Electricity (mills/kWHe)					(i) 2.07 +1		
COSTS	Fuel Cycle Capital ($/kWe) (i)		1.72 0	1.98 +1	0		4.94 0	2.65 +1
COSTS	Fuel Cycle O&M ($/MWe-yr)		?	5.50 +3	0		?	?
LABOR MH/MWe-yr	CONSTRUCTION (i)	Engineering	3.52 -1	1.68 0	0	5.93 +1	1.11 0	6.24 +1
		Field Super. & Adm.	2.09 -1	4.11 -1	0	1.01 +2	7.51 -1	1.02 +2
		Field Unskilled manual	2.23 -1	2.28 0	0	8.87 +1	1.53 0	9.27 +1
		Field Skilled manual	1.02 0	8.71 0	0	3.71 +2	4.91 0	3.86 +2
		TOTAL	1.80 0	1.31 +1	0	6.20 +2	8.30 0	6.43 +2
	O&M (k)		7.16 +1	?	0	2.50 +2	?	?
ENERGY	Primary (l)	(MWth-yr /MWe-yr)	2.64 +2	2.50 +2	2.56 0	2.56 0	(e)	2.64 +2
		Fuel Efficiency	9.50 -1	1.02 -2	1.00 0	3.90 -1	(e)	3.78 -3
	Ancillary	(MWth-yr /MWe-yr)	2.26 -3	1.02 -1	0	0	1.88 -4	1.05 -1
MATERIALS MT/MWe-yr	CONSTRUCTION (j) METALS	Structural	1.57 -3	2.65 -2	0	1.35 0	2.06 -2	1.40 0
		Pipes	4.09 -3	1.05 -2	0	1.26 -1	2.01 -3	1.43 -1
		Major Equipment	1.45 -2	2.13 -2	0	1.47 -1	7.05 -3	1.90 -1
		Other Equipment	7.92 -4	6.73 -3	0	2.73 -1	5.03 -4	2.81 -1
		TOTAL	2.10 -2	6.50 -2	0	1.90 0	3.02 -2	2.02 0
		Concrete	5.15 -2	2.21 -1	0	1.77 +1	7.55 -3	1.80 +1
	O&M		--	--	--	--	--	--
LAND (m) m^2/MWe-yr	Temporarily Committed	TOTAL	1.58 +2	2.75 +1	0	4.82 +1	2.94 0	2.37 +2
		Undisturbed	1.10 +2	2.48 +1	0	4.16 +1	2.88 0	1.79 +2
		Disturbed	4.80 +1	2.70 0	0	6.30 0	4.09 -2	5.80 +1
	Permanently Committed		1.81 +1	3.60 -2	0	6.30 0	1.69 -2	2.44 +1
WATER (m)	(10^6 Liters/MWe-yr)		1.57 -1	3.04 -1	0	1.78 +1	1.47 -2	1.83 +1

Net
3.75 -1

Table H-1: Footnotes

a. Includes the mining and milling of about 56% of an LWR's U_3O_8 requirement as well as about 8 MT of ThO_2 (thorium oxide) per annual steady state reload. Actually, it may not be necessary to mine thorium for some time as it is a byproduct of other mining operations (e.g. phosphate mining), as well as being abundantly available in Canadian uranium mill tailings. Eventually, though, some thorium would need to be mined. A facility lifetime of 20 years was assumed for both uranium and thorium mine-mill complexes.

b. Includes conversion of uranium ore to UF_6 and subsequent enrichment of this material as well as the fabrication of HTGR fuel elements. The U-233 produced in the reactor (from virgin ThO_2) is assumed to be recycled, U-235 is assumed to be recycled only once and ThO_2 is assumed not to be recycled (actually three types of fuel rods are fabricated, but as the HTGR fuel cycle is in general quite complex, it is not completely described here and the interested reader is referred to Ref. (183) for a complete description). A 30 year facility life was assumed.

c. Transport costs and resource utilizations (which are again small) are included in totals given for other stages of the fuel cycle.

d. The model HTGR power plant is assumed to have thermal efficiency of 39%, a capacity factor of 75% and a plant lifetime of 30 years.

e. Includes fuel reprocessing as well as waste management. A 30 year life is assumed for these facilities.

f. Based on data given in References (6), (8), and (37) we assume a mid-1974 capital cost of $380/Kwe, excluding interest during construction Adding interest during construction at 10.5% and 6% inflation, the real interest rate is 4.25%. For a 3.75 year construction period, we get a total capital cost of about \$440/Kwe.

g. In accordance with data given in Ref. (6) conventional O & M costs for an HTGR are assumed to be equal to those for an LWR.

h. Based primarily on data given in References (11), (159), (183), and (20), the initial core was assumed to require 39 MT of ThO_2, 374 MT of U_3O_8, 469 MT of UF_6 conversion, 339 MT of separative work and 37 MTH* of fuel element fabrication. Annual reloads were assumed to require 8 MT of ThO_2, 87 MT of U_3O_8, 110 MT of UF_6 conversion, 79 MT of separative work, 8.3 MTH of fuel element fabrication, and 7.3 MTH of fuel element reprocessing, with an additional 64 MT of U_3O_8, 79 MT of UF_6 conversion and 57 MTSWU required for each of the first two annual reloads because recycled material is not assumed to be available for reload until the second annual reload after discharge. Fuel-cycle timing data were again taken from Ref. (11). Using these data the present value of the fuel cycle costs of the life of the reactor was calculated to be 298.2 million dollars.

i. Collecting the following data from above:

$IT = 4.40 \times 10^8$ (from row one of the Table).
$N = 5.26 \times 10^6$ (from row two of the Table).
$PV(FC) = 2.98 \times 10^8$ (from note h above).

We can again use Equation (*) of note g, Table A-1 to calculate the electric generation cost as:

$$EC = \underset{\text{Capital}}{7.49} + \underset{\text{O \& M}}{8.09} + \underset{\text{Fuel}}{5.14} = 20.67$$

j. Fuel cycle capital costs and construction labor and materials requirements are from Ref. (8). Once again the fuel cycle capital costs are not annualized, while the construction labor and materials requirements are annualized by the assumed facility lifetime.

---

* Metric ton of heavy metal (MTH).

k. We assume that O & M personnel necessary to run a thorium mine is identical to that necessary to run a uranium mine and also that the number of people reeded to run an HTGR power plant is identical to that necessary to run an LWR power plant. The reader is, therefore, referred to note l of Table F-1 for the appropriate references.

l. Uranium mining is assumed to be 100% efficient. The 95% efficiency for Harvesting Fuels is therefore based on a 95% mill efficiency as given in Ref. (2). The primary energy input to the harvesting fuels activity (equivalent to the energy in the extracted ore) is assumed to be 22,000 KWht per gram of uranium, which corresponds to the energy that would be produced if every atom of uranium fissioned. For ancillary energy requirements see References (3), (6), (181), (182). and (184).

m. Primarily from References (3), (6), (181), (182) and (184).

Table 4-2: HTGR

Environmental Releases			HARVESTING FUELS (a)	UPGRADING FUELS	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTAL
AIR	Non-Radioactive (metric ton/MWe-yr)	NO_x	8.3-14.3 -3	1.2 -2	2.7 -3	0	1.9 -3	2.5-3.1 -2
		SO_x	3.1 -2	2.6 -2	0	0	4.0 -3	6.1 -2
		Particulates	6.6 -3	2. -2	0	0 e	2.7 -3	3.0 -2
		HC	1.1 -3	2.7 -3	0	0	2.8 -3	6.6 -3
		Toxic Metals	0	0	0	0	0	0
		Other	2.2 -4	(b) 4.7 -4	0	0	(b) 1.2 -3	1.9 -3
		Total	4.7-5.3 -2	6.2 -2	2.7 -3	0	1.3 -2	1.2 -1
	Radioactive (curies/MWeyr)	Rn	8.3-49.5 -3	0	0	--	0	8.3-49.5 -3
		H-3	--	0	0	1.0-32.0 -1	(i) 33.3 0	33.4-36.5 0
		Kr-85	--	0	0	(f) 5.3-16.6 0	66.6 0	6.7-6.8 +2
		Trans U	--	(c) 7.5 -8	0	0	8.0 -7	8.8 -7
		Other	4.6-5.3 -5	0.08-15.4 -4	0	0	(j) 1.3-3.7 -1	1.3-3.7 -1
		Total	8.3-49.6 -3	0.08-15.4 -4	0	5.4-19.8 0	7.0 +2	7.1-7.2 +2
WATER	Non-Radioactive (MT/MWe-yr)	Silt	0	0	0	0	0	0
		Other	1.5-23.7 +1	2.5-5.7 -2	0	1.6-59.0 -1	(k) 2.5 -2	1.5-24.3 +1
		Total	1.5-23.7 +1	2.5-5.7 -2	0	1.6-59.0 -1	2.5 -2	1.5-24.3 +1
	Radioactive (curies/MWeyr)	H-3	--	--	0	9.2 -2	0	9.2 -2
		Trans U	--	3.7 -4	0	0	0	3.7 -4
		Other	1.4-3.2 -3	1.5 -4	0	0	0	1.6-3.4 -3
		Total	1.4-3.2 -3	5.3 -4	0	(g) 5.3-92.0 -3	0	7.2-95.7 -3
SOLID	Non-Radioactive	(MT/MWe-yr)	4.7-6.3 +4	1.9-7.5 -2	0	0	0	4.7-6.3 +4
	Radioactive (curies/MWeyr)	High Level (liters/MWeyr)	--	--	--	--	1.3 -2	1.3 -2
		Fission Prod.	--	--	--	--	4.5 +4	4.5 +4
		Trans U	--	4.3 -2	--	--	(l) 3.5 +2	3.5 +2
		Total	--	--	--	--	4.5 +4	4.5 +4
		Low Level (liters/MWeyr)	--	--	--	0	(m) 1.9 0	1.9 0
		Intermediate (liters/MWeyr)	--	--	--	0	(n) 2.0 +1	2.0 +1
		Buried Solid (m^3/MWeyr)	--	4.1 -1	--	0	2.5 -1	6.6 -1
		Tailings (curies/MWeyr)	6.1-8.3 -2	(d) 1.4 -4	--	(h) 6.6 +1	--	6.1-8.3 -2
THERMAL DISCHARGE (MWth-yr/MWe-yr)			1.7 -3	3.0 -2	0	1.56 0	8.0 -4	1.59 0

Table H-2: Footnotes

a. 56% of LWR uranium mining and milling requirement. See table E-2 and footnotes. Impacts from thorium mining would add about 10% to these impacts (3,184) but have not been added because sufficient thorium will be available for a long time as a byproduct of other mining processes.

b. Includes small amounts of HF^-.

c. Low end is from ref. 3 and high end from ref. 183.

d. Uranium and thorium (3) plus 8? kg uranium as UF_6 (0.03 Ci) in storage.

e. Plus 0.4MT dissolved solid in cooling tower drift.

f. Includes xenon.

g. Low end from ref. 7.

h. Stored solid waste (3).

i. With advanced controls: H-3 0.28 Ci
Kr-85 5.8 Ci.

The rest would be stored as H-3 hydrate and compressed Kr-85.

j. Mostly carbon-14.

k. HNO_3 (3).

l. Plutonium.

m. $8.5(10)^{-3}$ Mt thorium. In addition, $5.8(10)^{-5}$ MT (0.002 Ci) of uranium (2% U-235, 64% U-236, 34% U-238) to be sold or stored.

n. H-3 as hydrate (see note i) and $1.2(10)^{-3}$ Ci I-131 as powder (3).

See Refs. 179-185.

Table H-3: HTGR

Health Effects			HARVESTING FUELS (d)	UPGRADING FUELS	TRANSPORTING FUELS	CONVERSION TO ELECTRICITY	MANAGEMENT OF FINAL WASTE	TOTAL
OCCUPATIONAL (per MWeyr)	Accidental	Death	6.7-15.1 -5	4.0 -6	(e)	1.3 -5	(i) 2.7 -6	8.7-17.1 -5
		Injury	1.8-7.3 -3	1.0 -3	(e)	1.7 -3	8.0 -5	4.6-10.1 -3
		Prs-days lost	4.9-12.9-1	7.4 -2	(e)	1.5 -1	2.0 -2	7.4-15.3 -1
	Disease (a)	Death	1.9-3.4 -6	2.0 -6	(e)	4.0 -5	1.6 -6	4.7 -5
		Disability	3.9-6.7 -6	4.0 -6	(e)	8.0 -5	3.2 -6	9.3 -5
		Prs-Days	1.2-2.1 -2	1.2 -2	(e)	2.5 -1	9.9 -3	2.9 -1
PUBLIC (per MWeyr)	Accidental	Death	?	0	1.2 -5	0	0	1.2 -5
		Injury	?	0	1.1 -4	0	0	1.1 -4
		Prs-days	?	0	8.0 -2	0	0	8.0 -2
	Disease (a)	Death	?	?	(e)	(g) 1.0 -8	(i) 3.7 -5	3.7 -5
		Disability	?	?	(e)	2.0 -8	7.4 -5	7.4 -5
		Prs-days	?	?	(e)	6.2 -5	2.4 -1	2.4 -1
LARGE ACCIDENTS	Maximum Size	Death	10 - 10^2	?	?	(h)	?	--
		Disability	?	?	?	?	?	--
	Societal Risk	Death	?	?	?	(h)	?	?
		Disability	?	?	?	?	?	?
GENETIC RISK	TOTAL (b) (prs-rem Equiv./MWeyr)		7.8-? -3	2.0-? -2	(c) 2.2-5.0 -3	1.0-? -1	3.9 -1	5.2-? -1
SOCIAL EFFECTS	Fissile Material (c) (kg/MWeyr)	In Storage	--	0.11	0	2.0	0.05	0
		In Transit	--	0.7	(f) 1.4	--	0.3	2.0

Table H-3: Footnotes

a,b. See Table E-3, notes a and b.

c. Fuel cycles from ref. 3.

d. Requires about 56% as much uranium as the LWR cycles (3). See Table E-3, notes d and e. No thorium mining included here.

e. 40% less exposure than the LWR cycle (5, 6).

f. In transit from enrichment plant to fabrication plant, from reprocessing plant to fabrication plant and fabrication plant to reactor.

g. Annual average dose from the Ft.St. Vrain facility is estimated to be $5.0\ (10)^{-7}$ to the population within 14 miles. (185) For approximately 50,000 people and 330-Mwe at 75% capacity this is $1.0\ (10)^{-4}$ prs-rem/Mwe-yr.

h. There is some indication from British experience with gas reactors and separate estimates that HTGRs may be somewhat safer than LWRs (179,196). However, the data are not available to make a clear distinction. See Table E-3.

i. See note e.

j. World exposure from Kr-85 and H-3.